

ONPEAK MARKET DISPATCHABLE ENERGY FROM  
MEGAWATT SCALE FUEL CELLS AND STORED  
DIGESTER METHANE

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# ONPEAK MARKET DISPATCHABLE ENERGY FROM MEGAWATT SCALE FUEL CELLS AND STORED DIGESTER METHANE

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This dissertation shows that pure methane storage and megawatt scale fuel cell systems operated by a spot market dispatcher can provide revenue streams that are double to quadruple the revenue that would be collected from net metered biogas generation. When configured as recommended, these systems can provide up to 38 to 59% of the theoretical revenue from a spot market for the generator company (Genco) that dispatches the stored energy. It describes the implementation of the OnPeak Time Generation and Storage (OpTiGaS) System that achieves this level of performance. This system is based on:

- Computer executable simulations of biogas digester companies and an onpeak fuel cell dispatching Genco, working together to maximize biogas revenue on the electricity spot market;
- A unique method of scheduling onpeak megawatt scale electricity to the wholesale power grid using purified methane that is stored in gas holders;
- Interpretation of spot market data to minimize the risk of low and negative revenue times.

There are up to 2,950 dairy farms in NY that could potentially benefit from digester gas generation if they are properly configured to use OpTiGaS. Forty-one of these are large enough to operate stand-alone with their own Genco. For comparable outcomes, the rest can employ clustering agreements and codigestion of

food waste streams to achieve similar revenue streams. The analysis demonstrated several beneficial combinations:

- clustering digester sites by pipelines to make more than 1 MW fuel cell power plants if methane supply from one digester site is insufficient;
- scheduling one or two spot electric blocks totaling 8 hours/day only on spot market days for selling power to the grid, and;
- tuning gas holder size and generator size to make methane gas refilling steady each month without running empty.

Revenue from a cluster of three 600 milking cow farms and a 1.05 MW Fuel cell was up to \$20,400 per month. Revenue from one 1,700 milking cow farm and 1.1 MW fuel cell was \$21,141/month. The addition of manure to certain food wastes, such as used cooking oil and pasta, was shown to transform a 600 cow biogas production to look like a 1,700 cow facility's biogas production. For a large food processing plant, equipped with an 18 MW grid fuel cell and 2.56 MW onsite fuel cell, revenue was projected to be \$2.6 million/year for combined onsite energy savings and grid power sales.



## BIOGRAPHICAL SKETCH

Stefan Minott comes from Kingston, Jamaica where he completed his elementary and high school education. Introduced to the field of biomass renewable energy at an early age by his father and other engineers, the author was inspired to pursue a career in the engineering of living systems for the manufacture of food and energy from locally derived materials. He graduated from Swarthmore College in Pennsylvania with a Bachelors of Science in Engineering in 1997 where he focused on Energy Systems and Mechanical Engineering. After working for a year and a half at E.I. Dupont du Nemours and Co. Inc, as a Research Engineer in Bioinformatics and Computational Biology, he decided to pursue graduate studies in Agricultural and Biological Engineering at Cornell University. Stefan earned a Masters of Science in Biological & Environmental engineering at Cornell in 2002 and continued onto the PhD program at Cornell. Employment by John Deere, Seneca Foods Corporation, RNK Capital and Pace Energy & Climate Center during his studies broadened his professional experience in applying biomass energy and climate change to the industrial and financial sectors. His present interests include fuel cells, sustainability, combined heat power and cooling (CHCP), smart grids and rural eco-industrial parks.

To my family.

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## LIST OF ABBREVIATIONS

AC	alternating current
AEP	American Electric Power
ANSI	American National Standards Institute
CAFO	concentrated animal feeding operation
CHCP	combined heat, cooling and power
CHP	combined heat and power
CHR	contract heat rate
CIP	critical infrastructure protection
CIR	critical infrastructure resilience
CNG	compressed natural gas
COS	cost of service
CTC	competitive transition charge
DADRP	day ahead demand response program
DAM	day-ahead market
DE	distributed energy
DER	distributed energy resource
DG	distributed generation
DHS	Department of Homeland Security
DME	dimethyl ether
DOE	United States Department of Energy
DSASP	demand side ancillary services program
EE	energy efficiency
EDRP	emergency demand response program
EDT	eastern daylight time
EIA	Energy Information Administration
EMS	energy management system
EOC	Emergency Operations Center
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
EUE	estimated unserved energy
FERC	Federal Energy Regulatory Commission
FMCC	federally mandated congestion charges
GENCO	power generation company
GW	gigawatt
HAM	hour-ahead market
HR	heat rate
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utilities
IREC	Interstate Renewable Energy Council
ISO	independent system operator
LBMP	location based marginal price
LHV	lower heating value

LMP	locational marginal price
LNG	liquefied natural gas
LOLP	loss-of-load probability
MCFC	molten-carbonate fuel cell
MHR	market heat rate
MMBtu	millions of British thermal units
MW	megawatt
MWh	megawatt hours
NIMBY	not in my backyard
NIPP	National Infrastructure Protection Plan
NITS	Network Integrated Transmission Service
NRECA	National Rural Electric Cooperative Association
NYC	New York City
NYCA	New York control area
NYPA	New York Power Authority
NYPA ECC	New York Power Authority Energy Control Center
NYDPS	New York Department of Public Service
NYISO	New York independent system operator
NYPSC	New York Public Service Commission
NYSDEC	New York State Department of Environmental Conservation
NYSRC	New York State Reliability Council
O&M	operations and maintenance
OHR	operational heat rate
$P_{Elec}$	electricity spot market price
$P_{NG}$	natural gas spot market price
PJM	Pennsylvania New Jersey, Maryland interconnection
PPA	power purchase agreements
PEM	proton exchange membrane
POD	point of distribution
POU	publicly owned utilities
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facility
RE	renewable energy
ROR	rate of return
SCR	Special Case Resources
SPP	small power production
T&D	transmission and distribution
THD	total harmonic distortion
TS	total solids content
USDA	United States Department of Agriculture
VOS	value of service
VS	volatile solids

# CHAPTER 1

## INTRODUCTION

Making provisions for digester methane storage and being selective about what time of day to dispatch power to the spot market is a novel, feasible and economically rewarding way to sell biogas power. This dissertation analyzed the spot markets for natural gas and electricity, and NY biogas cogeneration facilities in order to develop a computer-based model for dispatching power to the wholesale market. The model allows generator owners to collect higher revenues from on-peak cogeneration than they can using the present day method of electricity net metering.

Increasing demand for electricity, even as limits to the central power plant model become more apparent, has created a greater focus on integrating distributed generation systems into the power network structure. Furthermore, continuing depletion of fossil fuels and a greater awareness of the environmental impacts of extracting non-renewable fuel resources, are driving the need for greater efficiency in energy utilization as well as the development of renewable low-impact energy technologies. Waste to energy generators such as anaerobic digesters for agricultural wastes are an attractive option for production of renewable power. In spite of this natural fit, there has been relatively little investment in such systems outside of heavily government subsidized demonstration sites and research facilities. While deployment in the past was limited primarily by technical challenges, today, many of the challenges are economic. Without substantial subsidies, digester plants have a high risk of earning below their average operation costs under the traditional electricity net metering model.

To mitigate the risk of such stranded costs, previous studies have focused on boosting biogas production to increase electric capacity or improve onsite com-

bined heat and power efficiency.<sup>1-5</sup> Essentially, the increased biogas yield (in cubic meters, m<sup>3</sup>) per day from a single digester site, which resulted in both increased quantity of exported power (in units of megawatt-hours, MWh) per day and reduced quantity of imported fuel per day, was manipulated to increase profitability on that agricultural site. In contrast, my study shifts the focus to directly increasing revenue by increasing the hourly price per megawatt-hour price paid to the generator owner on the open market. This is achieved with the combination of long term storage of pure methane, energy conversion with a fuel cell, and an algorithm for scheduling near real time power dispatch that tracks and adapts to grid load forecasts, as well as spot market price signals and power contracts.

## 1.1 Motivation

Emulating, Henry Massalin\*, I provide this section, which summarizes my motivations for this body of work. By establishing a context for the reader, I hope to make the rest of the ideas presented here easier to grasp.

\*\*\*

In 2002, I showed with my master's degree research that the cogeneration capacity from biogas could be more than doubled with a molten carbonate fuel cell in comparison to traditional implementations using a biogas engine-generator set (genset).<sup>7,8</sup> Furthermore, farm cash spent on externally-purchased fuel consumption was reduced or eliminated when recovered heat was used to displace fuel purchases (propane & fuel-oil), heat the digester and reduce cooling costs. As a result, the exportable electricity to the power retail market from the digester site was increased, and the imported externally-purchased fuels was reduced. Both out-

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\*Henry Massalin's dissertation<sup>6</sup> was nominated for the 1992 ACM Distinguished Dissertation Award. It is often used as an example of a clear and lucid piece of academic writing worthy of emulation.

comes combined, increased the profitability of biogas cogeneration by over 21%. I was gratified when in 2004, Haubenschild Farm became the first dairy farm in the world to install a fuel cell<sup>9</sup> to take advantage of these findings. For my PhD work, I intended to continue my work with fuel cells. In addition, I intended to develop a waste-to-DME system and show that DME was a viable, sustainable and more economical vehicular fuel alternative than generating ethanol from food crops.

Prior to completing my PhD dissertation however, I was recruited to work in both the financial and policy making sectors of the environmental/agricultural industry. My time in these positions completely changed the direction of my work. I was aware of the basic concepts of the smart grid and distributed grid/distributed energy systems in a peripheral way because of my work with fuel cells. I however became intensely interested in such systems at this time and was afforded the resources for thorough research. In addition to this, I was exposed to a wide variety of state-of-the-art alternative fuel production systems and environmentally-friendly agricultural & industrial equipment and processes. I got to interact extensively with various stakeholders including the engineers and scientists that designed the systems, manufacturers, farmers, utility plant managers, investors and policy makers at various levels of governments.

While most of the stakeholders had a genuine interest in reducing pollution and working with technologies that were more environmentally friendly, that desire alone was not enough for any of them to invest in or adopt such technologies. The investors, for instance, were looking for projects that would generate a good return on investment for them and their shareholders within a relatively short amount of time. The utility companies were also interested in making money and were looking for distributed energy solutions that would make their operations more robust. The farmers were looking for ways to turn their waste into another



revenue stream. Industrial food processors were interested in ways to reduce their waste disposal costs and possibly make money on another value-added product. Depending on their politics, government representatives believed that they needed to invest in such technologies to reduce dependence on imported fuels; strengthen the grid and make it more resistant to extreme demands or deliberate sabotage; and to make the US a leader in the renewable energy industry.

Apart from the government, all the stakeholders were reluctant to participate unless someone else, namely the government, would pay for the projects and assume a significant portion of the financial risks. I also found, time and time again that in existing projects of this nature, the projects were profitable only because of incentives - incentives that were liable to change with changes in government.

I firmly believe that incentives and grants are still very important for building momentum in developing sustainable, environmentally friendly fuel alternatives, especially when it comes to the capital costs. I became convinced however, that for these technologies to be readily adopted and become widespread, they need to be economically viable once online. Any incentives at this stage, should simply be “icing on the cake”. I began to look for ways to combine my work with renewable energy systems, my newly acquired knowledge of smart grid and distributed energy systems with knowledge of how the energy markets work, in a way that would encourage more investment in waste-to-fuel systems in general, and anaerobic digesters in particular.

The solution I came up with and present in this dissertation is deceptively simple. In short, I show that fuel production from the digester needs to be separated from electricity generation and dispatching. I showed that by borrowing technologies from the natural gas industry, it is indeed feasible to store enough digester biogas to achieve this separation. Subsequently, one could be selective

about when, where and to whom, the electricity was sold to. I then developed a model that showed that being selective about what time of day to generate and dispatch power to the energy spot market is an economically rewarding way to sell biogas based power.

## 1.2 System Overview and Scope

Figure 1.1 illustrates the boundaries of the system defined for power generation and dispatching from anaerobic digesters. It includes two subsystems, referred to as SBA and SBB, which have inputs and outflows as well as processes and interconnections between them. These processes and flows are used to calculate materials and energy balances for an integrated system.

The aim is to find a combination of the following three parameters that will allow the generator owner to harvest more than 50% of the theoretical revenue from the spot market in blocks of 4 hours per day.

1. flow rate of biomass or biogas
2. methane gas holder storage size
3. generator size.

Capturing this level of revenue, will help make digester CHP systems economically viable without the subsidies that most of the existing systems rely on to achieve profitability.

The method for sizing the gas holder total volume and required methane refill rate (in standard cubic feet per minute, scfm) is applied to System SBA using a blackbox and “backwards in time” approach that uses historical time series data. Scheduling is done next with SBB using time series data to train the system to satisfy 5 days of 4 hour blocks of dispatching. Then forecast data from the New

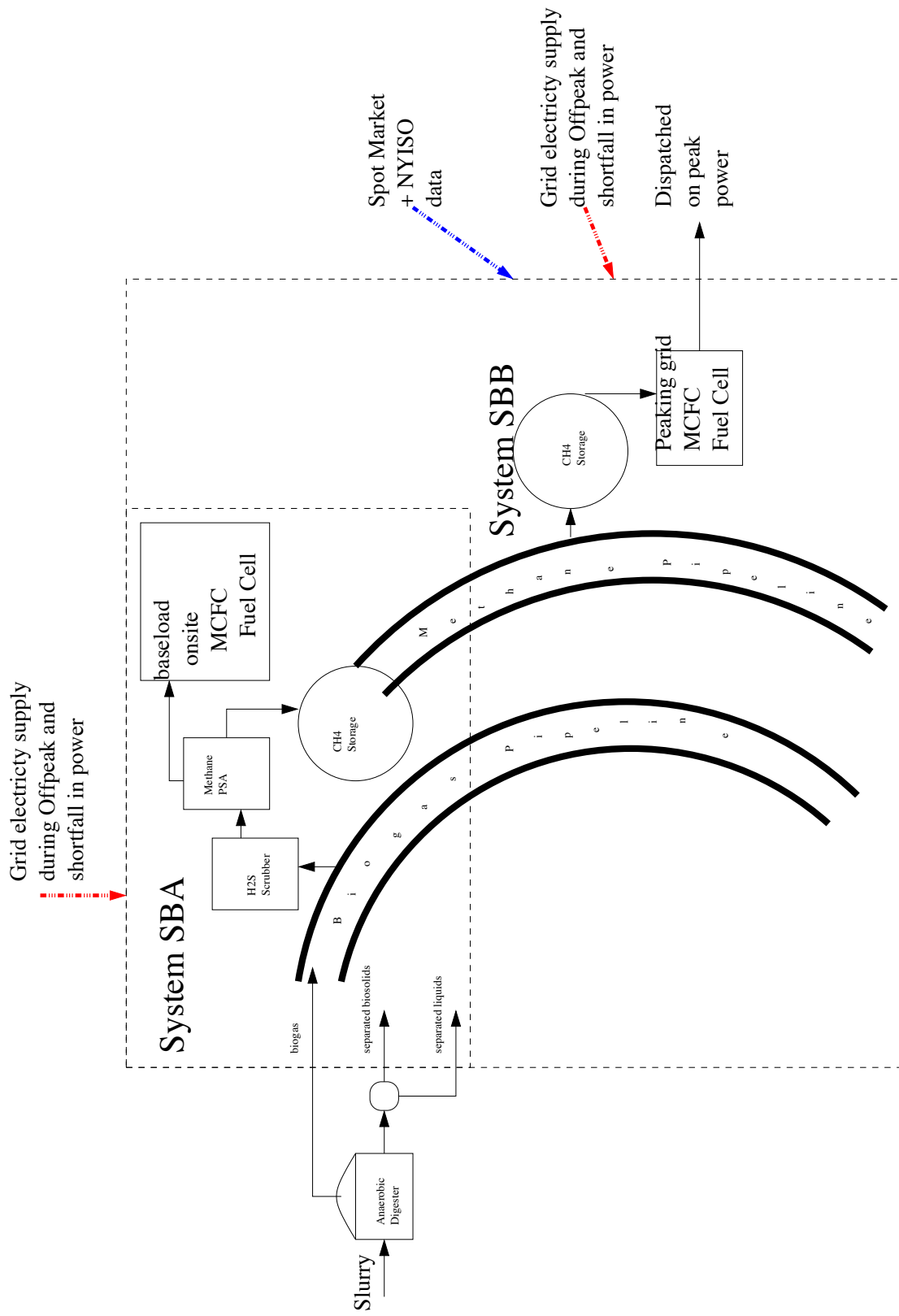


Figure 1.1: Integrated Power dispatch system and system boundaries. System SBA models the steady state production of biogas production and methane storage while system SBB primarily models the dispatch decisions and their effects.

York Independent System Operator (NYISO), who manages the wholesale power market and electricity price signals for New York State, is used in a “forward looking” way to schedule dispatching with ever improving estimated data based on a 7 day horizon, 1 day horizon, then 1 hour ahead data with the possibility of using real time (5-minute ahead) data if fuel availability is not under question. Fuel availability is checked regularly because the generators are programmed to shut off below a minimum volume of methane in storage. The minimum threshold ensures that sufficient methane fuel is available the following day for another round of 4-8 hours of dispatching to the spot market.

### **1.3 Organization**

Chapter 2 provides relevant background of the electrical grid and digester operations. It also provides a less technical look and back-of-the-envelope analysis of my proposed model. In doing so, this chapter illustrates the novelty of my model for electricity generation and dispatching from biogas. Chapter 3 provides a framework for evaluating the total energy resource available at a digester site using manure from a generic 2,000 cow dairy farm as a template.

By modeling the digester and grid generator operations with a steady state network method in Chapter 4, the technical feasibility is assessed for adding biogas purification and pure methane storage processes to the existing manure handling system. Given known digester input streams, Chapter 4’s model is used to select the size of gas holder volumes and determine the required steady state biogas flow rate for a desired range of electricity generation capacity to satisfy expected energy loads.

In Chapter 5 stored methane in systems boundary SBB is piped to a set of very efficient grid connected molten-carbonate fuel cells (MCFC). I set out to answer

the question of whether monitoring the price signals from NYISO to schedule and execute the power dispatch would be economically rewarding. This involves first testing the feasibility of unit commitment of a 1 MW MCFC generator dispatch schedule during a 7 day horizon using the stored biogas and a steady hourly refill rate. Secondly, day-ahead electricity pricing data for the next 24 hours is used to calculate the expected hourly \$/MWh revenue. The next step runs simulations of the Genco according to the above hourly generator on/off schedule. The actual revenue collected by the Genco has the chance to increase over those previously calculated hourly expected revenue by the Genco dispatcher continuously monitoring hour ahead  $P_{elec}$  and  $P_{ng}$ . That real time monitoring finalizes the decision to go online and sell power as planned, or go offline and face whatever penalty stipulated by the NYISO. Those final decisions, however, are important to reduce costs and increase revenue that hour because the Genco has been involved in power purchase agreements, contracts and other forms of risk management to protect its energy income stream.

The rest of the chapters present the results and conclusions from case studies of real digester sites using the models developed in Chapters 3 through 5.

## 1.4 Contributions

My work provides an algorithm and decision making tool called OnPeak Time Generation and Storage (OpTiGaS) for on peak power dispatching decisions. It was created for generator owners to dispatch onpeak power using price signals from NYISO and available methane storage from neighbouring digester sites or long distance biomethane pipelines. It also demonstrates how financial arrangements to pipe and store pure methane storage between the generator owner and digester owner through a mechanism called tolling agreements is better for the digester

owner than the alternative of running generators directly on digester gas. My work opens the door for biogas Gencos and other alternative energy Gencos to further combine OpTiGaS with other kinds of risk management strategies, energy storage, local renewable energy resources, and conventional energy resources once they become spot market participants. Use of OpTiGaS was shown to minimize the risk of generating power during low revenue times of the week, lock in profit margins and help to increase cash reserves for the Genco and associated digester sites in anticipation of low market days. Companies adopting such a generation and storage system are expected to amass cash reserves to operate through cyclical low points every year, highly lucrative periods and also tumultuous periods of the financial markets.

Policy makers and energy researchers can also use the dispatch system to assess the effect of market rules, economic incentives and standard interconnection requirements on Gencos that sell biogas based energy and their surrounding communities. This comprehensive high revenue yielding model is not existent today for dairy biogas and other organic waste processing sites. Therefore, OpTiGaS dispatching creates a niche for expanding the role of agriculture in providing clean, green power to the smart grid and hopefully helps to increase the number of digester based generators from around 25 dairies in New York today to hundreds of dairy and food waste processor digester sites in the near future.

## CHAPTER 2

### RELEVANT BACKGROUND

The electricity grid is an expansive network of centralized mega and gigawatt scale generators that are connected with high-voltage transmission and lower voltage distribution lines to virtually every business, home and facility in the country. Reliable and affordable energy has always been vitally important to the USA's industrial success and public welfare. Electricity generation and consumption must be balanced across the entire grid to minimize power outages. Needless to say, the utility companies that perform this function were highly regulated entities. They were in fact, regional monopolies governed by the Public Utility Holding Company Act (PUHCA) that was issued in 1935.<sup>10,11</sup> Under the Act, utilities were required to build plants to serve the growing energy needs of their customers. They were also allowed to charge regulated cost-of-service rates, in addition to a reasonable level of profit. As some utilities invested in expensive technologies such as nuclear energy in the 1970s, big industrial energy users begun lobbying for deregulation so they could avoid paying higher costs. They wanted to be free to purchase power from the least expensive utility company, not necessarily, the closest one.

The lobbying efforts paid off. Beginning in 1992, the wholesale market for electricity generation was deregulated by the Energy Policy Act adopted by the United State Congress (EPAAct 1992), then further with the passage of EPAAct 2005.<sup>10,11</sup> The intent of this deregulation was to increase customer selection of energy suppliers with the hope of reducing electric cost to the end user. The upside for power generators was that they could now sell energy to the highest bidder instead of at a rate approved by their local utility commission. It also became possible for smaller, energy companies to compete with big centralized power plants. Both EPAAct 1992 and EPAAct 2005 were built on the legislative

gains of Public Utility Regulatory Policy Act (PURPA) in 1978 that included the allowance of renewable energy and distributed energy plants to become qualifying facilities who could sell power to the grid without many of the barriers previous put up by local utilities.<sup>12–16</sup>

In essence, with deregulation, the generation of power was separated from the transmission and distribution so that it was no longer a vertically integrated monopoly. Subsequently, investments in power generation grew without concomitant investments in the transmission and distribution grid. It also became much more difficult to model flows on the grid and provide adequate transmission capacity at any given time, since power plant outputs were now dictated by market prices. Incidentally, the increased generation capacity had made the electrical grid less stable. This point was underscored by the Northeast Blackout of 2003. On August 14th 2003, a transmission line overload in Ohio, set off a cascade of outages that left over 50 million people in North America without power for up to two days. The outage had significant negative impacts on interstate and commuter passenger rail transport, cellular communication networks, municipal water supply systems and municipal sewage treatment plants among others. International air transport and financial markets were also affected. The U.S. Department of Energy (DOE) estimates the economic damages associated with the blackout at about \$6 billion.<sup>17</sup>

Deployment of smart grid technology and a partial return to localized energy production and consumption in the form of distributed energy systems, have emerged as one of the most practical solutions for a more stable grid.<sup>18</sup> The smart grid calls for the integration of intelligent meters, sensors and controllers to monitor the grid in real time and optimize grid operations while minimizing the risks for system failure.<sup>19–21</sup> Distributed energy generating technologies include diesel engines, solar photovoltaic panels, fuel cells and microturbines that make it possi-



ble for end users to generate their own electricity with the option of selling excess power to the grid.

The distributed energy solutions augment the centralized utility in many ways. The benefits include increased generation capacity (especially valuable during periods of peak electric demand), voltage support, deferred transmission and distribution line construction, and less loss of power through transmission.<sup>22</sup> In the last 5 years, the federal government has passed legislation to encourage additional renewable energy installations. These include the Energy Independence and Security Act of 2007 (EISA), the Emergency Economic Stabilization Act of 2008 (EESA) and the American Recovery and Reinvestment Act of 2009 (Recovery Act).<sup>10,23</sup> The last one was aggressively pushed by President Obama to stimulate green jobs and green businesses to lift the economy out of the recession that started in 2008. Notably, the Recovery Act of 2009 provided \$4.5 billion for investment in smart grid technologies as part of the total \$43 billion for energy-related programs.<sup>10</sup>

Farms, especially those large enough to be classified as Confined animal feeding operations (CAFOs), tend to be large energy consumers. In addition, they are also typically located in rural areas with thin electrical grid distribution or located at the end of major distribution lines. Consequently, they may be the first to experience brownouts and blackouts. To reduce the effects of such production reducing events, many farms and CAFOs have on-site generators that qualify as distributed generation systems. A significant but increasing number of CAFOs, realizing the benefit of using anaerobic digesters, not only for odor control and animal waste management but also for biogas production, have begun to utilize biogas as a viable fuel alternative for running diesel engine generator sets, hot water heaters and in a few cases, absorption chillers. The trio of products: combined heat, cooling and power (CHCP), is referred to as cogeneration (cogen). Cogeneration significantly

reduces farm energy use and provides an avenue for additional revenue when excess power is sold to the grid. In addition to direct sales, digester generator sites can provide a host of ancillary services to their local grid. One of the vital ancillary service for the utilities is static VAR compensation (SVC). SVC relates to improving the quality of the power as it is transferred from the power plant to the end users through high voltage transmission wires, stepping transformers, substations, distribution bus wires, feeder wires (feeders) and finally the meter to a customer's house or business facility. SVC can either be added at the transmission bus level or distribution bus level. The SVC service significantly reduces the incidence of brownouts. SVC added at the distribution level by a distributed generator owner is a much less expensive and more reliable way of regulating voltage. This is discussed further in some detail in Section 2.2 below. Farms can thus improve the quality of electricity for their whole community by providing SVC service to the local utility in addition to distributed power generation.

The most current statistics from the US Energy information Administration, show that clean-tech renewable power sources in 2009 made up approximately 7.7% of electrical generation capacity in the United States.<sup>25</sup> Digester-based electricity has great potential as a scalable source of clean electrons for the grid. This is especially important as older plants that use polluting technologies, such as coal burning, are retired. As of December 2011, Environmental Protection Agency (EPA), reported that there were only 176 digesters (Figure 2.1) in the United States.<sup>24</sup> The EPA also noted that there are at least 8,241 dairy and swine farms where installation of biogas digesters are technically and economically feasible.<sup>24</sup> The potential for this technology becomes even clearer when other animal feed operations such as those for beef cattle and poultry and other non-farm sites such as waste water treatment plants, and food waste processing sites are considered.

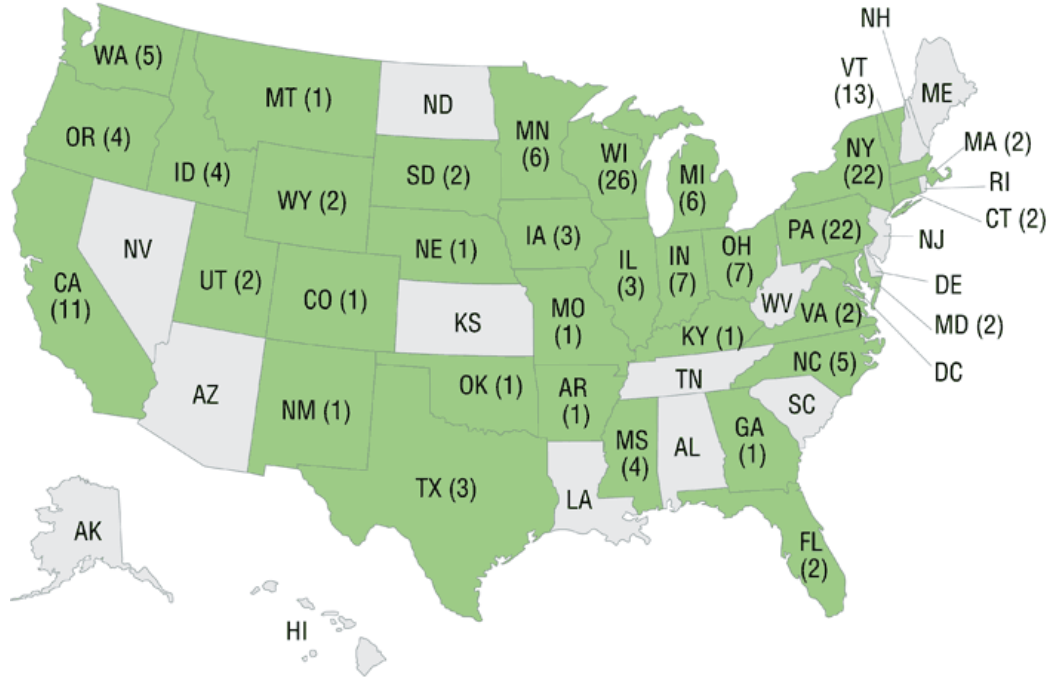


Figure 2.1: Number of operating agricultural digesters in the USA by state, as of December 2011. This includes 161 on-farm digesters and 15 centralized or regional digesters.<sup>24</sup>

Focusing on only New York state (NYS), there are hundreds of dairy farms with more than 400 cows, the threshold identified by Jewel et al. to sustain a digester. Figure 2.2 shows hundreds of the geographically dispersed dairies with more than 400 milking cows. Very few of these farms convert manure into energy. In fact, New York State has twenty three operational digester facilities,<sup>26,27</sup> some of which only started operating in the year 2010 (see Appendix D.1).

In addition to dairies, food processing plants and waste water treatment facilities among others, are also candidates for waste-to-energy digester sites. Figure 2.3 shows the abundance of food processors in New York state. Just like dairies, food processing plants are often large energy consumers with vast quantities of effluents that need to be treated for sanitation purposes before release. Currently, these plants pay considerable tipping fees (in the range of \$40 to \$120 per ton) to have their effluent trucked and treated off-site.

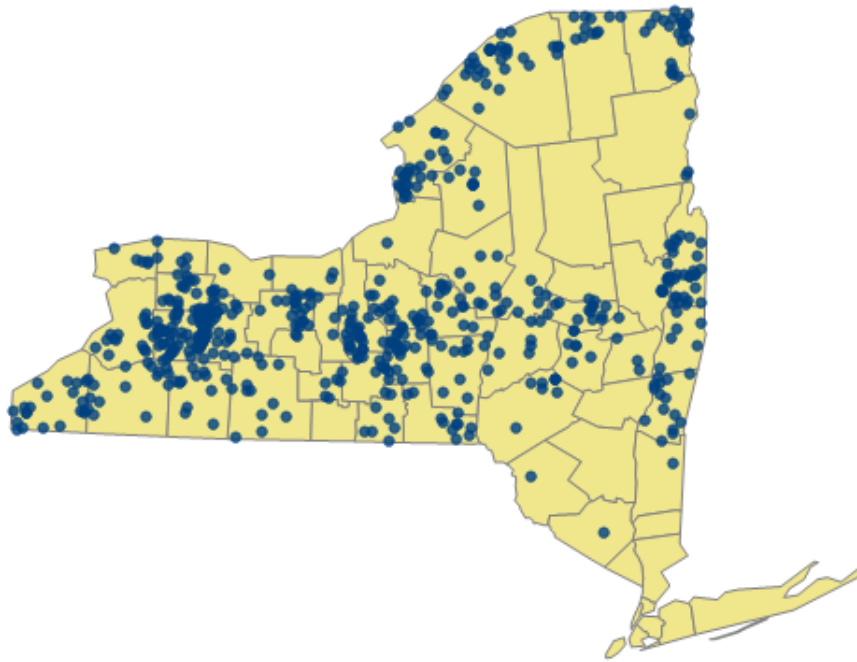


Figure 2.2: GIS map showing dairy farm CAFOs in all counties of New York state.

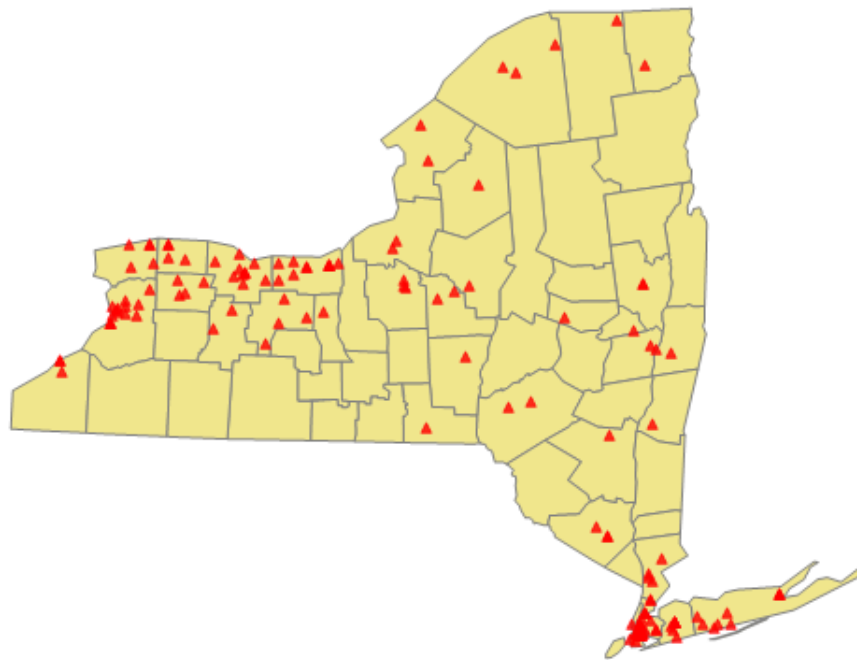


Figure 2.3: GIS map showing food processing plants throughout New York state.

The rest of this chapter gives a brief introduction to anaerobic digestion of manure, food wastes, and other organic wastes. It goes on to show how these resources and related technology at digester sites fit into the context of wholesale power markets and to show that they are an important niche area to study, solve problems for, and promote.

## 2.1 Anaerobic Digestion of Organic Waste

Anaerobic digestion is a biochemical degradation process that breaks down organic material, such as dairy manure, into biogas in the absence of oxygen. The biogas is made up of methane ( $\text{CH}_4$ ), carbon dioxide and other trace gases including hydrogen sulfide ( $\text{H}_2\text{S}$ ), nitrogen and carbon monoxide. The methane in the biogas contains the bulk of the energy value of the biogas. To generate electricity, the methane-rich biogas is typically fed to an engine and generator set (genset). Most sites use a standard diesel engine but a few use microturbines (which are very efficient aero derivative jet turbines used for auxiliary power when jets are sitting at the airport). The biogas can also be processed into pipeline quality methane gas by a molecular sieve or pressure swing absorption(PSA) process and used in the same way as natural gas.

The waste gas from the PSA (referred to as tail gas in the industry), left unused after most of the methane has been extracted, has too little energy to be used as a fuel. It is usually disposed of in a catalytic converter or flare. The solids left at the end of digestion are valuable as a soil amendment. They can also be dried and pelleted into a combustible fuel or reused as animal bedding. For additional discussion about fuel production from manure via biochemical fuel pathway and thermochemical pathway refer to the Appendix.

My dissertation proposes three major deviations from how electricity is typi-

cally generated and dispatched from a digester. First, provision is made for long term methane gas storage. Secondly, a fuel cell is used for electricity generation instead of a diesel engine or microturbine. The combination of the first two changes, allow electricity to be generated and dispatched, contrary to the norm, on an asynchronous schedule designed to increase the \$/kWh rate received from the grid for electricity sold.

## **2.2 Providing Electricity Voltage & Frequency Support to Publicly Regulated Utilities**

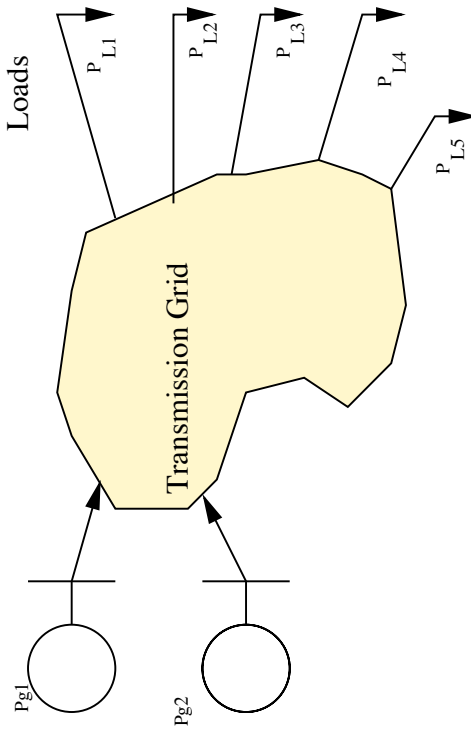
The modern grid is based on transferring alternating current (AC) from central power plants and distributed generators to electricity demand users. Power flows from supply side to demand side by generators, transmission lines and distribution lines (GTD lines) to loads at end users as depicted in Figure 2.4.

As real power traverses the grid equipment and wires to houses, commercial and other end users, the power quality degrades and has to be adjusted all along the line. Power quality is adjusted with strategically planted utility equipment such as shunts, capacitors, and actually specially sited generators like gas turbines and other distributed generation technologies.

Ideally, AC power is characterized by sinusoidal current (I) and voltage (V), usually 60 Hz or 50 Hz depending on the country. Power  $P = I \times V$  and the root mean squared (RMS) method is used to calculate the magnitude of current or voltage. If the voltage and current lead or lag each other by  $90^\circ$  this would result in no real power flow. Misalignments must be corrected by static VAR systems (SVS) such as static VAR compensators (SVC), static compensators (STATCOM), shunt capacitors, induction reactors or by shutting down bad inductive loads in

## Centralized Model

Generation

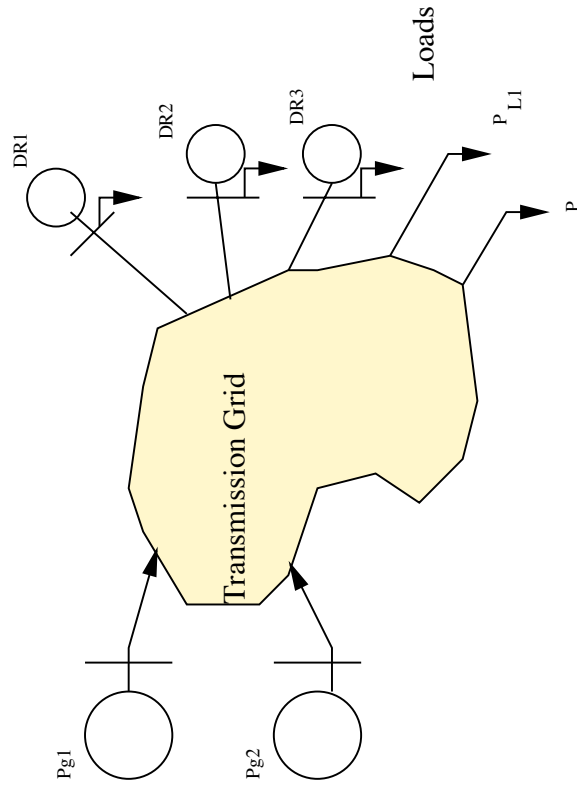


Distribution Grid

## Distributed Generation Model

Central Generators

Distributed Generators



Distribution Grid

Figure 2.4: Centralized generation model versus distributed generation model showing the generation, transmission and distribution (GTD) parts

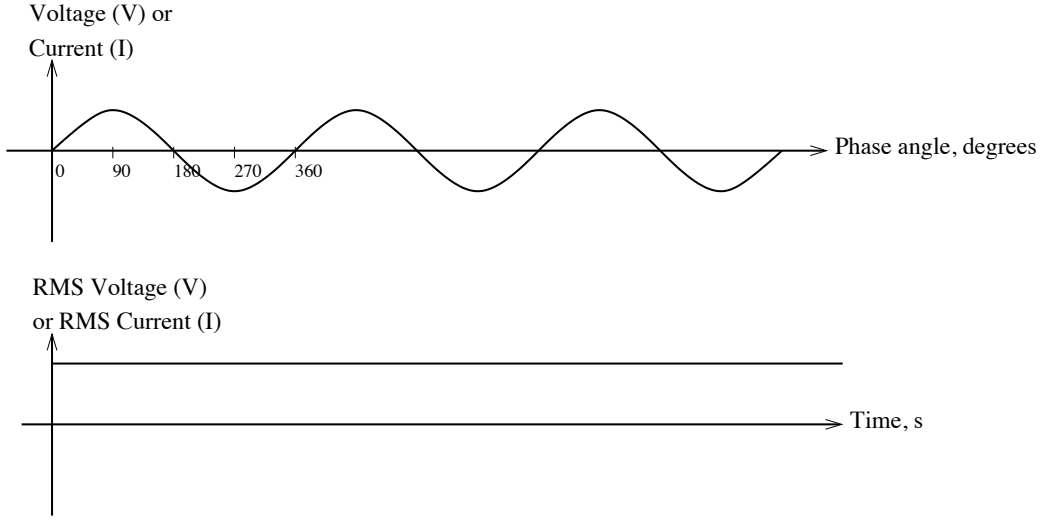


Figure 2.5: Ideal (top) sinusoidal power curve and (bottom) flat RMS steady power curve equivalent to power sinusoid.

order to return the grid's  $V$  and  $I$  to required stable set points for voltage, phase and frequency.

Utility companies typically add SVC and STATCOM to the transmission bus on the “supply side” as a method for cleaning up the power quality and correcting power factors so that end users, even those at the furthest ends of the grid, receive the required capacity to operate in the modern society. Another viable alternative is for the utility company to use an ancillary service method to add SVC to the “demand side”, at the end user's side of the meter which is connected to the distribution bus part of the grid.<sup>28–32</sup> As previously mentioned, one of the vital ancillary services for the utilities that can be provided by a distributed generator is VAR compensation at the distribution bus level.

Kincic et al<sup>31</sup> showed simulations of how effective this distribution bus voltage support strategy would be in also correcting power transfers on the transmission bus. Major benefits of adopting this distribution bus attached voltage support to the power lines include:

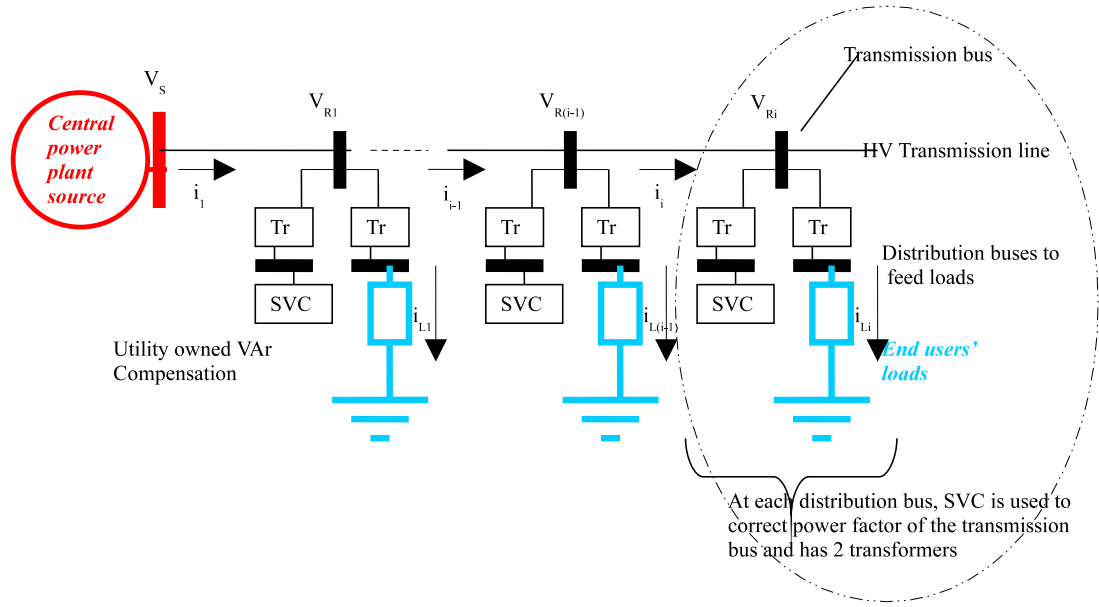
1. reduction by at least half of the required step up transformers



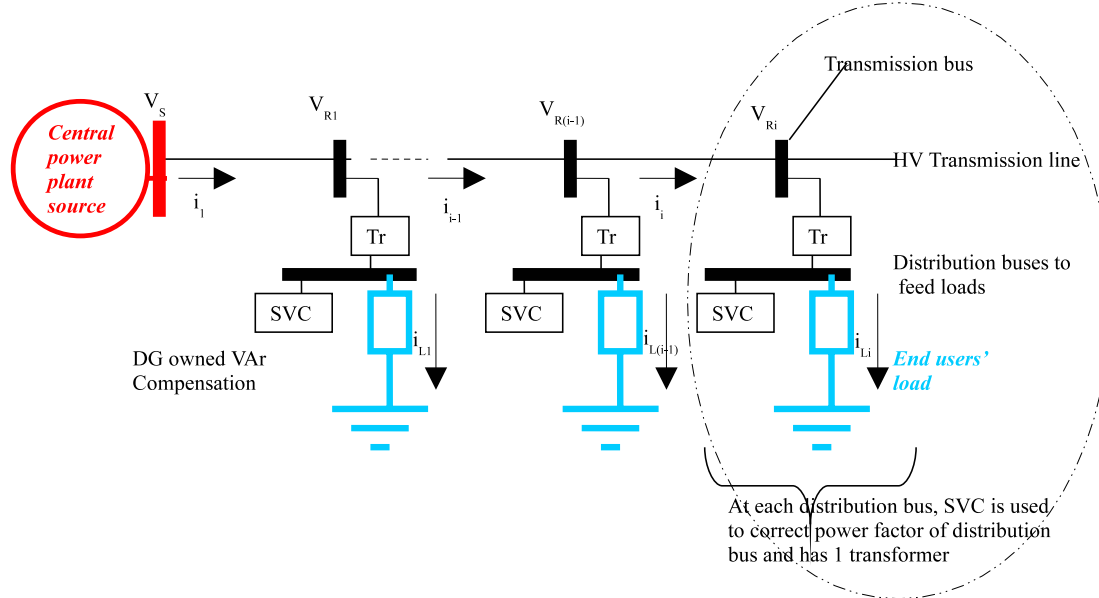
2. reduction in asset upgrades as a result
3. increased grid (N-1) reliability
4. less complexity for the utility operators
5. and if at the end of the line there was a DG/CHP system in addition to supplying VARs, the grid upgrades could be deferred (or eliminated because an end user financed it versus the utility investing in new infrastructure and capital expenses.)

Figures 2.6(a) and 2.6(b) shows how VAR compensation is used to correct power factor on the grid. In Figure 2.6(a), VAR compensation is placed on the transmission bus by the utility to make sure that the electrical power flows further down the transmission line is correct and high quality. Figure 2.6(b), shows the VAR compensation applied to correct the distribution bus power factor instead of correcting the transmission bus power factor. In this scenario, the transmission engineers concentrate on supplying adequate power to the distribution buses while the distribution engineers are not expected to worry about anything else but loads served by the distribution bus.

In addition to billing for total kWh/month, distribution utilities charge commercial energy users extra high rates based on their highest monthly electricity loads (\$/highest kW reading) and also for inductive loads. Often those high kW loads are due to low efficiency appliances and loads that turn on infrequently. A major class of such low efficiency electrical loads are made up of motor driven agricultural equipment, such as some of those used on large dairy farms to pump fluids and lift animal feed. With digester-based generators sited on the farm, dairy farms could not only provide their own onsite power to mitigate these charges but they could also enter into power purchase agreements to provide a host of ancillary services. Namely,



(a) Utility owned SVC connected to the transmission bus.



(b) DG owned SVC connected to the distribution bus

Figure 2.6: Voltage support applied to (a) the transmission bus or (b) the distribution bus. Note how applying VAR compensation on the distribution bus halves the number of transformers required to ensure the quality of the delivered power.

- Agreeing to reduce peak demand at the utilities request (demand response) for an annual cash incentive that reduces total payment from the farm to the utility,
- Agreeing to sell reactive power, VArS or SVC services to grid to correct the distribution bus power factor,
- Shutting off all but critical loads during peak demand hours (voltage and frequency support),
- Automatically starting some of the motors and pumps with self generated power before the rest of the grid is back online from a blackout (black start capability), and
- Make use of more energy efficient combined heat and power (CHP) to provide needed heat as well as electricity from one fuel source.

These benefits apply with other classes of commercial energy users with waste-to-energy generators, that utilize for example on landfill gas, used vegetable oil, food packaging waste etc. as their fuel source for power generation. Successful tests have been done to show the benefits of DG to the utility in providing ancillary services to avoid systems upgrades in transmission and distribution constrained areas in California, Washington, and Michigan.<sup>18-20</sup>

As utility companies see benefits from deployed DG and CHP, it becomes easier to make the case that public commission utility regulators need to setup economic mechanisms to decouple monetary benefits from power consumption only. Decoupling would allow the utility to share money from reactive power, VArS, SVC services, delayed investments, avoided capital upgrades, CO<sub>2</sub> reduction, etc. with the DG and CHP owners who provide “demand side” ancillary services.

## 2.3 Decoupling Power Sales For Biogas Digesters

Biogas power cogenerator facilities do not typically receive a large check every month from the utility companies for net injection of power to the grid. Instead at the end of the year, the local distribution utility calculates the difference between electrical power consumed from the grid (kWh) and electrical kWh sold to the grid. There are two outcomes at the end of the year in a transaction called net metering. If the net metered difference is a negative number, the utility pays or credits the facility at the avoided cost rate, which ranges from \$0.025 to \$0.06.<sup>4,7,8</sup> On the other hand, if the net metered difference is positive, the cogen facility pays the distribution utility company a check at the regular retail price which is on average, \$0.147 \* in New York State.

The avoided cost is usually the lowest price for electricity. This is the rate received by hydroelectric and nuclear power plants that are always on. More often than not, the avoided cost earnings will not cover the costs for running a digester. Digester sites with cogeneration facilities, however, do have a right to make just enough electricity for onsite power and sell no more excess. There is some evidence to show that this is currently the preferred mode of operation for unsubsidised sites where generators are shut off after on-site needs are met.<sup>34,35</sup> With the current payment scenario born from net metering, what incentive is there to sell the hard earned renewable energy? In fact, apart from those few digesters that gain additional income from food waste mixing and tipping fees, example Ridgeline Farm (formerly Matlink Farm) and Patterson Farm, continuous power sales do not look like a good investment without significant government and external financial subsidies.

Enter a different world where a generator owner could draft up a power purchase

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\*From example New York Electricity and Gas (NYSEG) electric bills in 2010<sup>33</sup>

agreement (PPA) with a utility or directly with a large private or public end user. In the case of PPA with a utility, the DG owner would consider good payment plans/rebates in addition to the PPA for supplying renewable bioenergy to meet the utilities transmission and distribution goals (renewable portfolio standard (RPS), carbon offsets, Kyoto protocol and international agreements for satisfying green energy demand of progressive users) to make it a win-win for both parties. In the case of PPA with another large private end user, the DG owner would factor in the cost of wheeling power through the grid infrastructure for a \$/kWh fee in addition to the negotiated fixed price (\$/kWh) for power delivered to the end user and reasonable price penalties (\$/kWh) for non-deliveries.

Long term power purchase agreements and emission reduction schemes affect consumer choices and energy generation behavior; it is a factor of benefits and favorable economics. States like New York that have significant barriers to new grid infrastructure construction but high concentrations of dairy, food processing and other waste-to-energy site potential, stand to benefit greatly from decoupling supply-side revenue from demand-side energy consumption. Decoupling of the revenue from volume sales of electricity (kWh or MWh) to all customer rate classes could provide a method to remove the disincentives the electric distribution utility faces from not collecting power income (\$/kWh) from energy consumption (kWh) that traditionally get paid back by their return on rate base, return of rate base and capital improvements.<sup>†</sup>

Again, systemic changes by the NYSPSC resulting in transition to revenue collection decoupled from electricity volume sales would opens up new ways for biogas electricity producers to make societal (and profitable) contributions in energy sales. Then no matter if the digester site buys little or no power from the

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<sup>†</sup>The author appreciates the colleagues at Pace Energy and Climate center for introducing him to this level of detail in the stakeholders for energy efficiency and demand side management.

grid, the utility gets a fee for just being connected. The utility or state agencies such as NYSEERDA can then focus on implementing many energy efficiency and DG initiatives to reduce the New York System Load for non generating customers and organizations. The digester site would then focus on maximizing its revenue and profitability from onpeak sales of electrical power and ancillary services.

## 2.4 Relevance of Digester Methane Storage

Mason Dixon Farm was one of the first plug flow digester sites developed in America in 1979.<sup>36</sup> The design was based in part on results obtained from research at Cornell University, New York, to develop low cost farm based anaerobic digester systems. The Mason Dixon farm is located in Pennsylvania and its digester is still successfully operating after nearly three and a half decades.



Figure 2.7: Mason Dixon Farm's original gas holder bag. Gas piped from the digester was stored in the bag to even out fuel supply to the electricity generator.

One of the original design specifications for that digester was a storage gas holder (Figure 2.7). The gas holder could store hours of methane and evened out



Figure 2.8: Gas inflates the soft top digester cover at AA Dairy Farm. There is no separate mechanism for gas storage. Gas generated is piped directly to the electricity generator.

the supply of biogas to the engine generator sets. Irregular biogas production was due to rapid or slow yields at different times of the day depending on a number of conditions. These conditions include the interval between adding fresh manure influent to the digester, temperature of the digester and effect of solar heating on the speed of bacterial methane production. Unfortunately, this extra gas holder step was eliminated in subsequent digester designs in favour of continually consuming all available methane to generate baseload electrical power and heat to the digester site. Any excess electricity was sold to the grid. See Figures 2.7 and 2.8 for pictures of the original Mason Dixon farm's gas storage bag compared to a conventional soft top plug flow digester at AA Dairy. As previously noted, unless the electricity selling price (\$/kWh) received by the digester owner is subsidized, the price paid for any excess electrical generating capacity is quite low. Subsequently, there is a risk that any costs incurred in manipulating digester conditions to increase biogas production may not be recouped. This dissertation shows that such risks can be

mitigated with appropriately sized gas storage. In fact, gas storage is required to increase revenue received for electricity sold to the grid.

Natural gas marketers routinely store millions of decatherms of methane during off peak spring and fall seasons in order to supply high demand during onpeak summer and winter seasons and special times of the day. In the winter the peak load is for heating water and air handling of buildings during two peak times of the day and in the summer the peak load is for refrigeration and air conditioning to prevent overheating during the hot middle hours of day. Similarly, pure methane can be stored during offpeak times at a biogas site. The stored methane would subsequently be converted by a generator owner in order to dispatch MW power to the grid to supply high demand prices (\$/MWh) on the spot market.

The technology to store large quantities of gas is thus available and easily adapted for digesters. In recent years, mainly to eliminated odors in urban areas and to cap green house gases, companies such as Siemens developed affordable and reliable gas holder technology for the wastewater treatment industry. Dystor is the Siemens brand for gas holders. Floating gas drums over water are also common and was commonplace for offshore natural gas pipelines in the UK. Digester methane and biogas cleanup facilities can employ gas holder technology.

Examples of biogas systems with gas holders are shown in Figures 2.9(a), 2.9(b) and 2.9(c). They are designed to fit on top of degassed effluent tanks and to temporarily store and scrub the methane produced of  $H_2S$ . These biogas systems shown are in operation in Germany, and made by EnviTec Biogas. The EnviTech biogas units scale modularly in 500 kW units up to 20 MW generating capacity. Other companies around the world offer similar construction of turn key biogas plant systems.

Gas holders have also been designed to be stand alone units without attach-





(a) 500 kW Biogas plant



(b) 2.5 MW Biogas park



(c) Three types of gas holder bags

Figure 2.9: Five examples of biogas cogen systems with gas holders. (a) 500 kW Biogas plant with 2 gas holder bags on effluent tank and primary digester, (Source: EnviTec Biogas, Germany). (b) 2.5 MW Biogas park with 10 gas holder bags on 5 effluent tanks and 5 primary digesters, (Source: EnviTec Biogas, Germany), (c) Three styles of Ecomembrane gas holder tanks, (Source: [www.biogasproducts.co.uk](http://www.biogasproducts.co.uk)).



Figure 2.10: Stand-alone Ecomembrane gas holder tank on the ground. (Source: Ecomembrane.com)

ment to slurry tanks or digesters as shown in Figures 2.10. For the biogas generator owner, piped biogas would be stored in these gas holder tanks or floating drum tanks not for hours but for days or weeks at a time. For extremely large biomethane producers like a food waste processing digester, landfill collection site or wastewater treatment plant, once the methane had been cleaned up and pressurized, the large producers might opt to measure the methane production, pay a NG access fee to the gas utility and park the methane into a NG pipeline during low demand months. Then later measure the extraction of the methane from the NG pipeline during high demand months, and calculate the net metered methane. They could remove all or most of the methane parked on the NG pipeline instead of storing it above ground in visible gas holders.

## 2.5 Fuel Cells For Increased Digester Power Potential

For optimum generation of digester biogas fuelled electricity, this dissertation proposes the use of a high temperature molten carbonate fuel cell (MCFC) over diesel gensets and microturbines (jet engines). While diesel gensets are the norm on digester sites, they are actually inefficient at producing electricity. Microturbines have better electrical efficiencies at 28% compared to 23% for agricultural diesel gensets. Both have a thermal efficiency of about 65 to 70% depending on whether recovered heat is fully utilized. Molten carbonate fuel cells (MCFCs) in contrast, generate electricity electrochemically without combustion and thus have electrical efficiencies in the range of 40-65% and total efficiency of 85 to 90% when you add back useful thermal energy consumption at the farm facility recovered from the fuel cell.<sup>37</sup>

In addition to at least double the efficiency of the diesel genset, MCFCs have a host of other benefits that include negligible amounts of gaseous emissions, quiet operation, high quality steam and hot water from heat recovery and modularity for scaling to larger sizes. Furthermore, MCFCs have a well deserved reputation for high reliability; six 9s or 99.9999% reliability, ie. less than 32 seconds downtime per year if there are no fuel and water supply issues. The major disadvantage of fuel cells are their high capital costs; \$3,600 per kW compared to conventional DG technologies at \$600/kW to \$1000/kW.<sup>38</sup> This price represents a significant cost reduction from about \$10,000/kW in 2003. Improvements in fuel cell production technology and higher volume production in the future should bring costs down even further. At this time, there are very attractive capital cost federal and state incentives for fuel cell installations that are not available for other DG technologies. In California for instance, fuel cell installations are essentially free for the digester owner after generous state incentives are factored into the costs that reduces the

capital investment. The cost of these fuel cells is discussed in Section 8.4 if one wants to skip ahead to check those costs.

A 2008 study by Fuel Cell Energy (FCE)<sup>‡</sup> showed that an MCFC fuel cell can actually run on tail gas which typically has a methane content of only 18.5%. Figure 2.11 shows the inflection point at 42% in the electrical efficiency ( $\eta$ ) graph that allows a MCFC fuel cell to produce electricity at an electrical efficiency of 47% as normal, albeit at a diminished MW rating. By that it is meant that a MCFC would generate power at 47% electrical efficiency from the range 100% pure methane feedstock all the way down to a 42% methane:58% carbon dioxide dilute mixture except the nameplate MW rating of the fuel cell would be diminished for the same influent fuel flowrate.

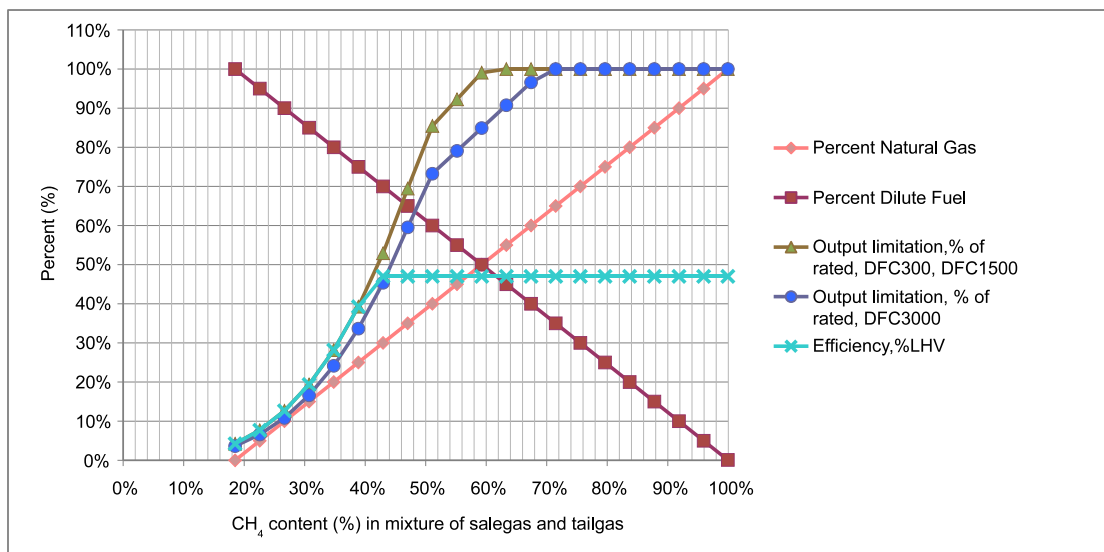


Figure 2.11: Performance effects of increasing the methane content of tailgas that is fed into three classes of molten carbonate fuel cells. (Source: Fuel Cell Energy)

Taking advantage of this knowledge, a fuel stream can be created by mixing some pure methane with the tailgas to elevate the methane content up to 42%.

<sup>‡</sup>Personal communication with FCE as part of a year long Walmart led dairy innovations collaboration that started at a “Greening the Milk Supply Chain” summit in Arkansas where farmers, industry representatives, university researchers, including me, and manufacturers including FCE formed a digester clustering and pipeline quality biogas committee.

Thus in this dissertation, I propose two fuel streams: 1) a high Btu, pure fuel stream for methane storage in gas holders having 100% pure  $\text{CH}_4$  content and 2) a low Btu stream for continuous onsite MCFC fuel cells using 42%  $\text{CH}_4$  content. Thus a higher percentage of the pure methane extracted from the digester biogas in the high Btu gas will be available for generation and dispatching to the grid without sacrificing onsite power production for low Btu gas. The result of this strategy would be a corresponding increase in dispatched power revenue while increasing onsite energy savings (from displacing grid purchased electricity with local onsite fuel cell power production.)

## 2.6 Cogenerator Sizing

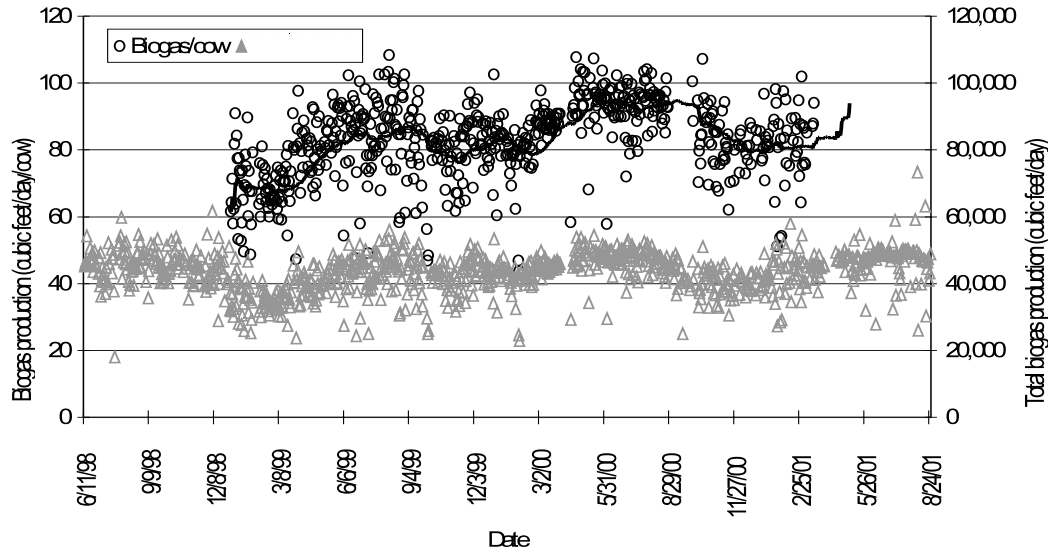


Figure 2.12: AA Dairy Total Biogas/day and Biogas production/cow/day.<sup>7</sup>

Typically generators at digester sites in the USA base their engine size on baseload capacity which in turn, is based on total biogas production in cubic feet per day. For example in Figure 2.12 from my Master's thesis,<sup>7</sup> reproduced here for

convenience, AA dairy was sized for a 130 kW genset with a 22% efficiency based on 60,000 to 100,000 ft<sup>3</sup>/day biogas production. This industry-wide approach only looks at daily or per time unit fuel availability to consume all the gas. With storage, one can look at biogas production from a cumulative perspective, that is, total fuel production over a time range. With such a cumulative approach, there arises a number of novel and creative options for generator sizing and dispatching.

In order to fulfil minimum generator requirements for participation in more lucrative energy markets for instance, it must remain true that the digester will run 24 hours, 7 days a week producing biogas. The generator however, will have the ability to switch on and go ONLINE to dispatch power only above a certain cumulative threshold of gas in storage. Subsequently, sinking below that threshold means the generator goes OFFLINE. For example, if 4 days of fuel production is converted into electricity in 1 hour, the generator size that the utility and markets see, would be  $4 \times 24 = 96$  times greater than the size for converting fuel into electricity everyday, 24 hours a day.

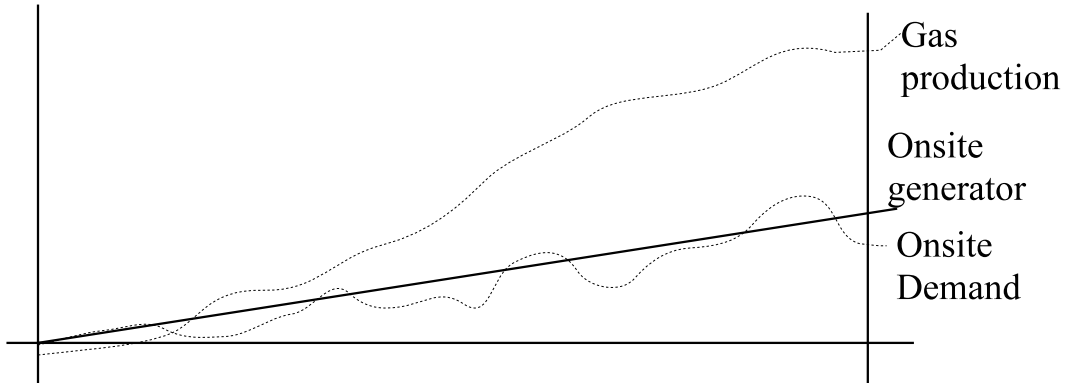


Figure 2.13: Cumulative biogas production, cogeneration and onsite demand.

The on/off decision would be based on onsite storage level and constraints, as well as spot market consumption patterns. In later chapters the on/off decision is explored in detail. The end goal is to size the equipment and run a generator owner's company (Genco) in such a way as to make bids unto the day-ahead market

and dispatch power profitably on the scheduled day and time.

## 2.7 Strategy for Increasing Revenue

Consider the electric price from the settled day-ahead electric spot market. The area under the electricity price curve in Figure 2.14 gives an idea of the theoretical maximum revenue that a co-generator can extract from the spot market. It also hints at price volatility in the day-ahead hourly blocks when dealing with the spot market. The dotted line shows the break-even point for revenue generation at 50% of the spot market. Wouldn't it be advantageous to collect a large percentage of that revenue as demonstrated in Figure 2.15? The shaded areas show when a generator was operating and making revenue while the clear areas show when the generator was off. Thus Figure 2.15 shows a generator making about 75% of the theoretical maximum revenue.

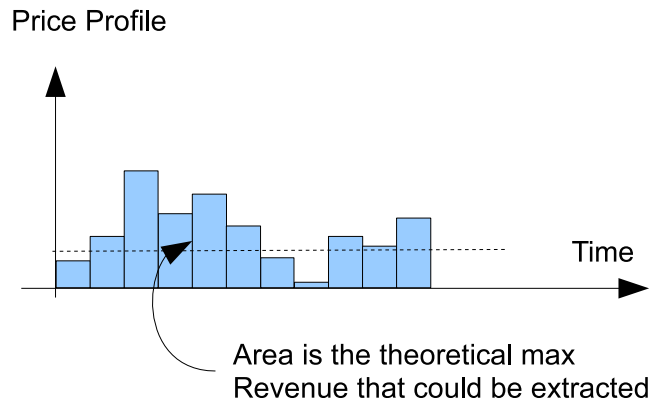


Figure 2.14: Theoretical Maximum revenue from the day ahead market

The volatility of the \$/MWh price on the supply side of the grid is beyond the control of cogenerator owners on the demand side. However, three important variables that can be modified by the biogas co-generator owner who delays electricity sales to the grid are:

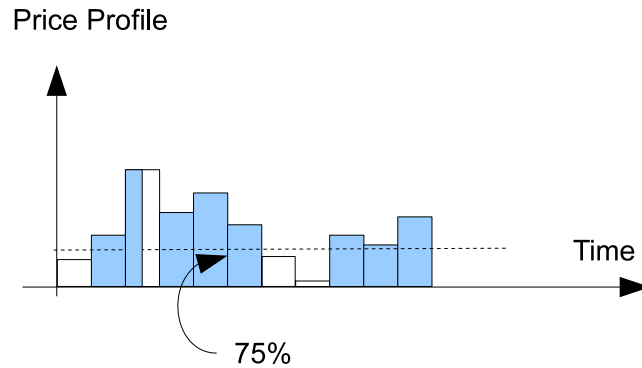


Figure 2.15: Capturing theoretical maximum revenue from day ahead market.

1. flow rate of raw manure biomass or biogas
2. storage size of methane gas holders
3. generator size

What best combination of these three variables will allow the generator owner to capture more than 50% of the theoretical spot market \$/MWh value (above the dotted line) in four hour blocks?

To answer this question, as this dissertation does, involves:

- coupling spot market data and scheduling computer algorithms to decide when to dispatch one or two MW scale fuel cells which consume stored methane on a daily basis (Chapter 5).
- analyzing a steady state network model based on the energy balance of a generator owner represented by System SBB which includes provisions for storing pipeline quality methane for many days in gas holders and a steady refill rate of pure methane every minute (see Chapter 4).
- utilizing data from a generic dairy digester to test simulations of both models before finally applying case study data was done in order to run computer simulations to see how fast they affected expected revenue collection at real digester operations.



A back of the envelope calculation is helpful at this stage to show that onpeak time only sales makes improvements to revenue. After this preliminary assessment we then turn to assumptions used to develop and test the two mathematical models. The steps for simulating the models and the sensitivity analysis is then described.

### 2.7.1 Back of the Envelope Calculations

Assuming 50,000 ft<sup>3</sup>/day of biogas is currently available for electricity generation on a dairy digester site. A continuously running 60 kW biogas engine-generator set (genset) would consume 2,083.33 ft<sup>3</sup>/hour biogas. Selling only to the spot market means only selling during onpeak hours of the weekdays, no weekends, no holidays, and no special market closure days.

According to Northeast Agriculture Corporation,<sup>33</sup> and Hsu<sup>39</sup> the onpeak hours are from 6 am to 11 pm. This is a period of 16 hours every Monday to Friday that is not a holiday. When cogen is offline, assume the methane would be stored in gas holder bags or cylindrical tanks.

In the first simple example, assume 24 hours online that the highest price is paid for 60 kW generation above the fluctuating \$/MWh spot market price. Let it be a fixed \$1,400/MWh to set an upper limit for the range of revenue potential. The revenue from the week's sale is thus 7 days x 24 hrs/day x 0.06 MW x \$1,400/MWh = 7 days x \$2,014/day = \$14,112/week as shown in Table 2.1 below and \$13,810/week profit after accounting for operation and maintenance (O&M) costs. By only dispatching cogeneration during the weekdays from 6am to 11pm without fuel storage, the revenue drops to 5 x 16 hr x 0.06 MW \* \$1,400/MWh = 5 x 1,344 = \$6,720 as shown in Table 2.2

MMBtu fuel consumed during 16 hrs on peak cogen (33,333 ft<sup>3</sup>/day) is less than the total gas from the digester 24 hrs/day (50,000 ft<sup>3</sup>/day). Therefore consuming

Table 2.1: Selling power at the highest onpeak price 24 hours/day, 7 days a week.

					normal							
	50,000	ft <sup>3</sup> /d			ft <sup>3</sup> /h	2,083.33						
								\$/MWh	\$/day	\$/day		
				am	pm	hrs	MW	bid	revenue	O&M		
				0	24	24	0.06	\$1,400				
	Su	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	Mo	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	Tu	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	We	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	Th	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	Fr	on	1			24	0.06	\$1,400	\$2,016	\$43.2		
	Sa	on	1			24	0.06	\$1,400	\$2,016	\$43		
						sum	50,000	ft <sup>3</sup> /d	\$14,112	\$302		
								profit	\$13,810			

Table 2.2: Selling power only during Onpeak hours from Monday to Friday without using fuel storage.

					on peak cogen w/o storage							
	50,000	ft <sup>3</sup> /d			ft <sup>3</sup> /h	2,083.33						
								\$/MWh	\$/day	\$/day		
				am	pm	hrs	MW	bid	revenue	O&M		
				7	11	16	0.06	\$1,400				
	Su	on	0			24	0	\$1,400	-	-		
	Mo	on	1			16	0.06	\$1,400	\$1,344	\$28.8		
	Tu	on	1			16	0.06	\$1,400	\$1,344	\$28.8		
	We	on	1			16	0.06	\$1,400	\$1,344	\$28.8		
	Th	on	1			16	0.06	\$1,400	\$1,344	\$28.8		
	Fr	on	1			16	0.06	\$1,400	\$1,344	\$28.8		
	Sa	on	0			24	0	\$1,400	-	-		
						sum	33,333	ft <sup>3</sup> /d	\$6,720	\$144		
								profit	\$6,576			

Table 2.3: Selling power only during Onpeak hours from Monday to Friday with fuel storage

		dispatch 0kw for 0 hrs during onpeak, 90kW for 16hrs									
	50,000	ft <sup>3</sup> /d				ft <sup>3</sup> /h	2,083.33				
								\$/MWh	\$/day	\$/day	
				am	pm	hrs	MW	bid	revenue	O&M	
				7	11	16	0.09	\$1,400			
	Su	on	0			24	0	\$1,400	-	-	
	Mo	on	1			16	0.09	\$1,400	\$2,016	\$43.2	
	Tu	on	1			16	0.09	\$1,400	\$2,016	\$43.2	
	We	on	1			16	0.09	\$1,400	\$2,016	\$43.2	
	Th	on	1			16	0.09	\$1,400	\$2,016	\$43.2	
	Fr	on	1			16	0.09	\$1,400	\$2,016	\$43.2	
	Sa	on	0			24	0	\$1,400	-	-	
						sum	50,000	ft <sup>3</sup> /d	\$10,080	\$216	
								profit	\$9.864		

one days worth of pre stored fuel in 16 hours would allow a bigger cogenerator, specifically one that can consume  $(24 \text{ hrs} \times 2,083.33 \text{ ft}^3/\text{hr})/16 = 3,125 \text{ ft}^3/\text{hr}$ . This is equivalent to a 90 kW genset, all other things being equal. Table 2.3 is the same as Table 2.2 with gas holder storage and onsite generation increased to 90 kW.

As shown above, the methane storage boosted revenue from the digester site, increasing it from \$6,720 to \$10,080. O&M costs also increased, assuming proportionality to dispatched MWh to the market.

Compare that to the normal avoided cost situation. Selling for avoided cost payments would get as low as \$20/MWh. As shown in Table 2.4, the revenue is low, in fact negative at -\$100, to generate assuming \$30/MWh O&M cost.

The best situation is bidding for all of the 16 hours such that for most of the period bid 0 MWh and sell 0.36 MW of cogeneration for 4 hrs only, as in Table 2.5.

The weekly revenue is the same \$9,864 as in Table 2.3 above but, each of the hours during the 4 hour period, the generator turns  $(50,000 \text{ ft}^3/\text{day})/(4 \text{ hrs}/\text{day}) = (12,500 \text{ ft}^3/\text{day})/(4 \text{ hrs}/\text{day})$  of one-day pre-stored fuel into 360 kW of power

Table 2.4: Selling continuously to grid for avoided cost payments (net metering).

			normal, net metering for avoided cost payment							
	50,000	ft <sup>3</sup> /d			ft <sup>3</sup> /h	2,083.33				
							\$/MWh	\$/day	\$/day	
			am	pm	hrs	MW	bid	revenue	O&M	
			0	24	24	0.06	\$20			
	Su	on	1		24	0.06	\$20	\$28.8	\$43.2	
	Mo	on	1		24	0.06	\$20	\$28.8	\$43.2	
	Tu	on	1		24	0.06	\$20	\$28.8	\$43.2	
	We	on	1		24	0.06	\$20	\$28.8	\$43.2	
	Th	on	1		24	0.06	\$20	\$28.8	\$43.2	
	Fr	on	1		24	0.06	\$20	\$28.8	\$43.2	
	Sa	on	1		24	0.06	\$20	\$28.8	\$43.2	
					sum	50,000	ft <sup>3</sup> /d	\$202	\$302	
							profit	-\$100		

Table 2.5: Four hours onpeak, Monday to Friday with fuel storage

			dispatch 0kw for 12 hrs, 360kW for 4hrs							
	50,000	ft <sup>3</sup> /d			ft <sup>3</sup> /h	2,083.33				
							\$/MWh	\$/day	\$/day	
			am	pm	hrs	MW	bid	revenue	O&M	
			11	3	4	0.36	\$1,400			
	Su	on	0		24	0	\$1,400	-	-	
	Mo	on	1		4	0.36	\$1,400	\$2,016	\$43.2	
	Tu	on	1		4	0.36	\$1,400	\$2,016	\$43.2	
	We	on	1		4	0.36	\$1,400	\$2,016	\$43.2	
	Th	on	1		4	0.36	\$1,400	\$2,016	\$43.2	
	Fr	on	1		4	0.36	\$1,400	\$2,016	\$43.2	
	Sa	on	0		24	0	\$1,400	-	-	
					sum	50,000	ft <sup>3</sup> /d	\$10,080	\$216	
							profit	\$9,864		

to earn  $\$2,016/4 = \$504/\text{hr}$  over the 4 hour block of time instead of the  $\$2,016/16 = \$126/\text{hr}$  per the 16 hour time block.

One interpretation we get is that by choosing 4 hours during the onpeak period of a day, this decision causes significantly higher payments from the spot market. Fortunately, 6 day ahead load forecasts from the NYISO and day ahead forecasts allow the generator owner to pick which of the 16 hours to bid 0 MW capacity to cogenerate and which ones to dispatch 4 hours of full name plate power. The generator owner gets paid the higher price of either the day ahead price of the real time spot market price.

The back of the envelope answer is, yes, under these favourable conditions it is indeed theoretically possible to increase business revenue by more than double by storing energy and selling for a few chosen onpeak hours instead of continuously generating biogas power. Going forward, conditions must be assumed to be more like the spot market and dispatch power only when the spark spread is in the money.

### **2.7.2 Eligibility for Wholesale Grid Interconnection**

Currently, digester sites in New York sell electrical power only to the retail market. Contrary to other industries where the wholesale price is typically lower than the retail price, the opposite is usually true for the electricity markets during onpeak hours. Wholesale prices are typically much cheaper during offpeak periods than the retail prices. The onpeak wholesale prices are so much higher than offpeak prices that revenues even out for the utilities and larger energy traders. For a small Genco with limited capacity and relatively high O&M costs, it is more desirable to sell electricity during the onpeak periods in the wholesale markets. Since electricity is not easily stored, utilities actually prefer that distributed Gencos operate during

peak periods to provide the excess capacity required.



## Program Feature Summary – Economic

	DADRP	DSASP
<i>NYISO Interface</i>	Demand Reduction Provider (DRP)	Demand Side Resource (DSR)
<i>Minimum Size</i>	1 MW	1 MW
<i>Capacity Payment</i>	None	None
<i>Payment</i>	Greater of energy marginal price or offer price, w/daily curtailment initiation cost guarantee	Reserve market clearing price
<i>Event Notification</i>	Notified by 11:00 a.m. of scheduled commitment for the next day (midnight to midnight)	Notified by 11:00 a.m. of scheduled commitment for the next day. Real-Time telemetered energy schedule
<i>Types of reduction</i>	Curtailable Load	Curtailable Load and Local Generation
<i>Penalty for Non-compliance</i>	Buy-through at greater of Day-Ahead or Real-Time price	Buy-through at Real-Time Reserve Market Clearing Price
<i>Credit Requirements</i>	Reduced from Generator levels	Reserve/Regulation levels
<i>Activation Priority</i>	Scheduled day-ahead if economic, no real-time schedule	Scheduled Day-ahead and Real-Time if economic

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Figure 2.16: NYISO requirements for cogeneration dispatch on the real time and day ahead wholesale market, source (Pratt, 2009)

Until December 2010, the cap for the maximum size to sell into the retail market was 500 kW per generator located on a digester site. This 500 kW is below the standard for a qualifying facility to sell electricity to the wholesale market. The rules of eligibility for the whole market are based on NYISO and the Public Service Commission's Standard Interconnection requirements.<sup>40</sup> NYISO lists some of the expected criteria and requirements to participate in Demand side Ancillary Services Program (DSASP) and Day Ahead Demand Response Program (DADRP).<sup>41, 42</sup>

When generator owners meets these requirements they can begin interacting in the wholesale spot market. My recommendation for a biogas Genco is to incrementally start off with a 1 MW sheddable load at the generator owner's site using the DADRP plan shown in Figure 2.16 first. Under this plan, the facility owner agrees

to disconnect load to comply with the day-ahead demand response signal. During that event the facilities load can be fully or partially supplied by onsite generation as long as the facility is totally disconnected from the grid. Next, we would shift the operations towards onpeak dispatchable cogeneration using the DSASP plan (also shown in Figure 2.16) when the facilities generation infrastructure is optimized to react faster and more predictably. DADRP does not get penalized for not being online as planned, however DSASP has a penalty cost for unplanned OFFLINE status of the generator. Under this DSASP plan, onsite 1 MW MCFC fuel cell systems would be eligible with day ahead and real time scheduling as per that table in Figure 2.16. The Genco is allowed a minimum of 2 MW total if solar, wind and other renewable energy is sold from the digester site.

### **2.7.3 Modelling and Simulation Strategy to Integrate the Different Knowledge**

As seen previously in the ball park/back of the envelope model, the potential revenue from the spot market was reasonably high to warrant further exploration as a research topic. A preliminary step in Chapter 3, quantifies electricity generation potential and availability of methane storage from cow manure. The methane energy is compared with the total energy resource inventory available from all collected raw manure at a generic 2,000 cow digester site to show that methane is only a small portion of all the embodied energy in raw manure. Information from a number of medium to large sized dairy digester studies in NY were surveyed to design the generic 2,000 dairy cow farm with digester.

Proceeding from those back of the envelope calculations the first part of the simulation strategy is making simplifying assumptions in order to develop a static model of the energy storage and dispatch problem at a dairy digester site in Chap-

ter 4. Koenig’s network modelling approach is introduced and used to derive closed form sets of equations and constraints used in the static model. Furthermore, Microsoft Excel spreadsheets and the open source Octave/Matlab programming language are used to test the static mass and energy balance of the static network model for the generic 2,000 cow dairy.

The second part of the strategy combined parameters and variables into a dynamic computer model for dispatching onpeak power to the grid in Chapter 5. I build on top of the static model for digester gas production and methane storage from the static model chapter including the novel idea of running fuel cells on PSA tailgas. The result is a tool for conducting risk management and revenue maximization at both a generator and digester company.



## CHAPTER 3

### QUANTIFYING METHANE AND OTHER STORABLE FUEL POTENTIAL AT DIGESTER SITES

This chapter assesses the quantity of storable fuels at anaerobic digester sites. In particular we examine dairy digesters that already cogenerate heat and power using biogas. The aim is to establish a resource inventory. Energy can be converted from organic wastes at a digester site using two energy platforms: a biochemical energy platform and a thermochemical energy platform. Anaerobic digestion is classified as a biochemical platform. The total embodied energy of the raw manure, including the quantity of storable pipeline quality methane is evaluated. Embodied energy of other storable fuels such as DME and biooil from thermochemical platforms like pyrolysis and gasification are also estimated. The reader can choose to read this storage chapter now or return after the reading the modelling and application chapters without loss of reading flow.

In this energy inventory exercise, I quantify the total energy available from manure and compare it to the energy from power generation using biogas. The material and energy balances in Figures 3.1 and 3.2 represent the results of this chapter but before that I am going to walk through the assumptions and reasoning behind calculating the values from first principles and raw data.

Many parameters are needed to perform the static and dynamic modeling studies. Most manure, methane and storage characteristics in the simulation are drawn from field measurements conducted by my research group and collaborators.<sup>7,27,43–45</sup> Total solids (TS) and volatile solids (VS) data were taken from recent New York case study farms along with the yield of digested solids and digested liquid after passing through a screw press separator.<sup>46–48</sup> Biogas production rates were estimated based on the literature;<sup>49–52</sup> earlier measurements<sup>7</sup> and

trends from case studies.<sup>7,27,43,53</sup> PSA and Fuel cell characteristics were derived from manufacturer specification sheets and operational experience. \*.

Some notes on the values used in this analysis are given below. Each value was varied roughly in accordance with the degree of its uncertainty. Parameter estimation was aided by personal communication with manufacturers, as well as the cited sources. The resulting table of constants is presented in Table 3.1 along with their respective notes and sources.

### 3.1 Calculated Biogas Production from 2,000 Milking Cows

On a generic dairy CAFO with 2,000 milking cows, the collectable manure is calculated by:

$$\begin{aligned} Manure_{lbs} &= cows \times Manure_{lbs/cow} \\ &= 2,000 \times 150lbs/day = 300,000lbs/day \text{ of raw manure} \end{aligned} \tag{3.1}$$

This assumes a 1,400 lb mature Holstein cows producing 150 lbs/day/cow of raw manure as in Table 3.1a. The raw slurry is a mixture of gutter scraped manure from the freestalls and milking parlors with some dilution by wash water (assuming bleach free and antibiotic free.)

Raw manure is assumed to be gutter scraped on the generic 2,000 cow farm and pumped into an anaerobic digester or codigester for biological conversion of volatile solids (VS) into biogas production. VS is only a fraction of the total solids (TS) contained in the manure. In general  $TS_{content} = 13.3\%$  of the raw manure (Table 3.1, b) and  $VS_{content} = 85\%$  of the total solids (TS) (Table 3.1, c) so

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\*Personal Communication with Fuel Cell Energy, 2008; Guild Associates, 2006; QuestAir, 2008

Table 3.1: Technology Coefficients

	Product	Raw Material	Technology Coefficients	Notes	Source
a	raw cow manure	milking cows	150	lbs/1400 lb holstein	Wright
b	total solids	raw manure	13.30%		Jewell, Wright, Inglis
c	volatile solids	total solids	85.00%		Jewell, Wright, Inglis
d	recalcitrant solids	volatile solids	56.00%		Jewell
e	raw biogas	volatile solids	5	ft <sup>3</sup> /lb VS destroyed	Gooch, Weeks, Luddington
f	raw biogas	volatile solids	60.00%	methane content	Minott, Scott, Wright
g	separated solids	digested slurry	50.00%	screwpress	Roos, EPA, Wright
h	separated liquid	digested slurry	50.00%		Roos, EPA, Wright
i	scrubbed biogas	raw biogas	99.95%		industry assumption
j	adsorbed sulfur moisture and particles	raw biogas	0.05%		industry assumption
k	pure methane	scrubbed biogas	99.50%	content	Questair, Guild Associates
l	pure methane	scrubbed biogas	100.00%	PSA product	Fuel Cell Energy, Inc
m	tail gas	scrubbed biogas	18.50%	content	Fuel Cell Energy, Inc
n	tail gas	scrubbed biogas	100.00%	PSA tailgas	Fuel Cell Energy, Inc
o	fuel refill to storage	pure methane	99.50%	CH <sub>4</sub> content	Fuel Cell Energy, Inc
p	fuel refill to storage	pure methane	69.00%	gas holder refill	Fuel Cell Energy, Inc
q	onsite baseload MCFC	pure methane	31s.00%	PSA product	Fuel Cell Energy, Inc
r	onsite baseload MCFC	tailgas	100.00%	PSA tailgas	Fuel Cell Energy, Inc
s	onsite baseload MCFC	tailgas + methane	42.20%	mixture	Fuel Cell Energy, Inc
t	grid MW fuel cell	gas holder	100.00%	CH <sub>4</sub> content	Fuel Cell Energy, Inc
u	grid MW fuel cell	pure methane	39	scfm/300 kW	Fuel Cell Energy, Inc
v	grid MW fuel cell	pure methane	156	scfm/1.4MW	Fuel Cell Energy, Inc
w	grid MW fuel cell	pure methane	312	scfm/2.8 MW	Fuel Cell Energy, Inc
x	grid power output	pure methane	1.4	MW size	Minott, Fuel Cell Energy, Inc
y	onsite baseload	tailgas + methane	300	kW size	Tulare county, Fuel Cell Energy, Inc

$$M_{TS} = TS_{content} \times Manure_{lbs} \quad (3.2)$$

$$= 13.3\% \times 300,000 \text{ lbs/day} = 39,900 \text{ lbs/day}$$

$$M_{VS} = VS_{content} \times TS_{content} \times M_{TS} \quad (3.3)$$

$$= 85\% \times 39,900 \text{ lbs/day} = 33,915 \text{ lbs/day}$$

Note that there are biodegradable volatile solids (BVS) and non biodegradable biosolids. Non-biological solids and recalcitrant solids (in Table 3.1d) including mineral salts, sand, stones, cellulosic and hemicellulosic material do not normally get broken down in anaerobic digestion but emerge unconverted after the 20 day hydraulic retention time (HRT) in the digester effluent.

Biogas production yield ( $BGY_{VS}$ ) is assumed to be 5 ft<sup>3</sup>/lb of influent VS (in Table 3.1e).<sup>4,7</sup> Raw biogas is assumed to be 60% methane (in Table 3.1f) , 40% CO<sub>2</sub> and trace gases including H<sub>2</sub>S that must be removed. Thus biogas production is given by:

$$BG_{ft^3} = BGY_{VS} \times M_{VS} \quad (3.4)$$

$$= 5 \text{ ft}^3/\text{lb of VS} \times 33,915 \text{ lbs/day} = 169,575 \text{ ft}^3/\text{day}$$

Biogas production from a 2,000 milking cow manure digester = 169,575 ft <sup>3</sup> /day
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In terms of the methane production only, the methane yield on biogas is

$$CH_4_{ft^3} = BG_{ft^3} \times BG_{CH_4 \text{ content}} \quad (3.5)$$

$$= 169,575 \text{ ft}^3/\text{day} \times 60\% \text{ of biogas} = 101,745 \text{ ft}^3/\text{day}$$

Moles of methane at standard atmospheric temperature and pressure (STP) is calculated with the formula:

$$P_1 \times V_1/T_1 = P_2 \times V_2/T_2$$

where,

P1 = pressure of biogas at ambient conditions, 1 atmospheres (ATM),

P2 = pressure of biogas at STP conditions, 1 ATM,

V1 = 101,745 ft<sup>3</sup>/day (methane production),

V2 = V1.T2/T1 (volume of biogas in litres in STP conditions),

and

T1 = 35°C = 308.15 K (temperature of biogas at ambient conditions),

T2 = 0°C = 273.15 K (temperature of the biogas at STP conditions).

Also using the metric volume conversion factor

$$1 \text{ ft}^3 = 28.317 \text{ L},$$

then methane production in moles is

$$\begin{aligned} CH_4 \text{ Moles} &= CH_4 \text{ cubicfeet} \times 28.317 \text{ L.ft}^{-3} \times \frac{T2}{T1} \times \frac{1 \text{ Mole}}{22.4 \text{ L}} \\ &= 101,745 \text{ ft}^3/\text{day} \times 28.317 \text{ L.ft}^{-3} \times 273.15 \text{ K}/308.15 \text{ K}/22.4 \text{ L.Mole}^{-1} \\ &= 114,012.04 \text{ moles methane/day@STP} \end{aligned} \quad (3.6)$$

Given that the molecular weight of methane is 16.042 g CH<sub>4</sub>/mole, methane production in tons per day is

$$\begin{aligned} CH_4 \text{ Tons} &= CH_4 \text{ Moles} \times \text{molecular weight of } CH_4 \\ &= 114,012.04 \times 16.042 \text{ g } CH_4/\text{mole} = 1.828 \text{ milliongrams/day} \\ &= 1.828 \text{ tons/day in the raw biogas} \end{aligned} \quad (3.7)$$

Methane production from a 2,000 milking cow manure digester = 1.83 tons/day

Similarly, given the molecular weight of carbon dioxide (44.01 g CO<sub>2</sub>/mole), the mass of CO<sub>2</sub> in the raw biogas can be calculated as follows:

CO<sub>2</sub> production:

$$\begin{aligned}
 CO_{2\ ft^3} &= BG_{ft^3} \times BG_{CO_2\ content} \\
 &= 169,575\ ft^3/day\ of\ biogas \times 40\%CO_2 \\
 &= 67,830\ ft^3/day
 \end{aligned} \tag{3.8}$$

Moles of CO<sub>2</sub> produced:

$$\begin{aligned}
 CO_{2\ Moles} &= CO_{2\ ft^3} \times 28.317\ L.ft^{-3} \times \frac{T_2}{T_1} \times \frac{1\ Mole}{22.4\ L} \\
 &= 67,830\ ft^3/day \times 28.317\ L.ft^{-3} \times 273.15\ K/308.15\ K/22.4\ L.Mole^{-1} \\
 &= 76,008.13\ moles\ CO_2/day
 \end{aligned} \tag{3.9}$$

Mass of CO<sub>2</sub> produced:

$$\begin{aligned}
 CO_{2\ Tons} &= CO_{2\ Moles} \times molecular\ weight\ of\ CO_2 \\
 &= 76,008.13 \times 44.01\ g\ CO_2/mole \\
 &= 3.3451\ tons/day.
 \end{aligned} \tag{3.10}$$

Quantity of CO <sub>2</sub> from a 2,000 milking cow manure digester = 3.35 tons/day
--

Energy content of the biogas assumes combustion of methane, not the inert CO<sub>2</sub>.

Using the methane's lower heating values (LHV) of 50.01 MJ/kg,<sup>54,55</sup> the energy content of raw biogas is:

$$\begin{aligned}
 BG_{LHV} &= CH_{4\ Tons} \times \frac{1\ Ton}{1000\ kg} \times CH_{4\ LHV} \times \frac{1\ day}{24\ hrs} \times \frac{1\ hr}{3600\ seconds} \\
 &= 1,828.984\ kg/day \times 50.01\ MJ/kg \times 1\ day/24\ hrs/day \times 3,600\ sec/hr \\
 &= 1.058\ MJ/s = 1.058\ MW
 \end{aligned} \tag{3.11}$$

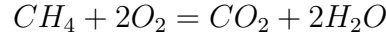
Energy content of the raw biogas = 1.06 MW LHV
--

## Carbon offset from biogas methane

By combusting the methane or using it in a fuel cell, the methane in terms of CO<sub>2</sub> equivalents can be found from:



but keeping it simple, we assume ideally that 1 mole of methane combusts ideally to 1 mole of CO<sub>2</sub> and 2 moles of water if oxygen is not constrained.



The moles and mass of CO<sub>2</sub> calculated from the moles of CH<sub>4</sub> in Equation 3.6 are:

$$\begin{aligned} CO_2 \text{ Moles} : CH_4 \text{ Moles} &= 1 : 1 \\ &= 114,012.04 \text{ Moles} : 114,012.04 \text{ Moles} \\ \therefore CO_2 \text{ Moles} &= 114,012.04 \text{ Moles/day} \end{aligned}$$

and

$$\begin{aligned} CO_2 \text{ Tons} &= CO_2 \text{ Moles} \times \text{molecular weight of } CO_2 \\ &= 114,012.04 \text{ Moles} \times 44.01 \text{ g } CO_2 / \text{mole} \\ &= 5.01767 \text{ tons/day in the raw biogas} \end{aligned} \tag{3.12}$$

In other words, combusting the methane produced 5.018 tons of CO<sub>2</sub>. However, on a molecule by molecule basis the greenhouse gas warming potential (GWP) of methane (CH<sub>4</sub>) is assumed to be 21 times more effective than its carbon dioxide equivalent (CO<sub>2</sub>e) in retaining heat over a 100 year timespan.<sup>56–58</sup> Also on a kilogram by kilogram basis, or mass by mass basis, methane is 58 times more effective than its CO<sub>2</sub> equivalent over a 100 year timespan. The equations therefore

are:

$$GWP \text{ of } 1 \text{ Mole } CH_4 = 21 \times GWP \text{ of } 1 \text{ Mole } CO_2 \quad (3.13)$$

$$GWP \text{ of } 1kg \text{ } CH_4 = 58 \times GWP \text{ of } 1 \text{ kg } CO_2 \quad (3.14)$$

Using Equation 3.7, the CO<sub>2</sub> equivalent (CO<sub>2</sub>e) of methane:

$$\begin{aligned} CO_{2e \text{ methane}} &= CH_4 \text{ Tons} \times GWP_{CH_4} \\ &= 1.83 \text{ tons of Methane} \times 58 = 106.14 \text{ tons } CO_{2e} \end{aligned} \quad (3.15)$$

Using Equations 3.15 and 3.10, the CO<sub>2</sub> equivalent (CO<sub>2</sub>e) of venting biogas is:

$$\begin{aligned} CO_{2e \text{ venting biogas}} &= CO_{2e \text{ of the } CH_4 \text{ in biogas}} + CO_2 \text{ in biogas} \\ &= 106.14 + 3.23 = 109.37 \text{ tons } CO_{2e} \end{aligned} \quad (3.16)$$

Using Equations 3.12 and 3.10, the CO<sub>2</sub> equivalent (CO<sub>2</sub>e) after combusting biogas is found by:

$$\begin{aligned} CO_{2e \text{ total}} &= CO_{2e \text{ after combustion of } CH_4} + CO_2 \text{ originally in biogas} \\ &= 5.018 + 3.23 = 8.248 \text{ tons } CO_{2e}. \end{aligned} \quad (3.17)$$

The carbon offset from combusting the biogas instead of venting it into the atmosphere from Equations 3.16 and 3.17 is thus:

$$\begin{aligned} CO_{2e \text{ offset}} &= CO_{2e \text{ venting biogas}} - CO_2 \text{ combustion of biogas} \\ &= 109.37 - 8.248 = 101.12 \text{ tons } CO_{2e}. \end{aligned} \quad (3.18)$$

Therefore, from an environmental pollution perspective, burning biogas (containing 1.83 tons of methane and 3.23 tons of carbon dioxide) or converting it directly into electricity instead of venting it directly into the atmosphere avoids 101.12 tons of carbon dioxide equivalents. This is good for the planet and maybe an additional income stream if sold to interested parties that buy carbon offsets.



## Electricity Derived From Energy Content of Biogas Methane

Continuously running a generator or fuel cell on biogas assumes energy conversion efficiencies. The maximum theoretical conversion rate is 3,412 kWh/BTU and a simple farmers' rule of thumb for methane is 1,000 Btu/ft<sup>3</sup> of pure methane. Thus, the maximum theoretical caloric value of the biogas in terms of BTU/day for the generic 2,000 cow dairy using CH<sub>4</sub> ft<sup>3</sup> in Equation 3.5 is:

$$\begin{aligned}
 TheoreticalMaxEnergy_{Btu} &= CH_4_{ft^3} * 1000 \text{ Btu}/ft^3 \text{ at STP} \\
 &= 101,745 \text{ ft}^3 \text{ methane/day} \times 1,000 \text{ BTU}/ft^3 \\
 &= 101,745,000 \text{ BTU/day}.
 \end{aligned} \tag{3.19}$$

A commonly used Caterpillar 3306 engine generator set (genset) that has been modified for natural gas and biogas by the addition of spark ignition has an electric efficiency of 22%. An MCFC fuel cell has a 47% efficiency. Daily power generation capacity for both systems are as follows.

$$PowerCapacity = efficiency \times \frac{3,412 \text{ kWh}}{Btu} \times CH_4_{ft^3} \times \frac{1 \text{ day}}{24 \text{ hrs}} \tag{3.20}$$

Applying Equation 3.20 to the Caterpillar engine we get:

$$\begin{aligned}
 PowerCapacity_{genset} &= 22\% \times \frac{3,412 \text{ kWh}}{Btu} \\
 &\times 101,745,000 \text{ BTU/day} \times \frac{1 \text{ day}}{24 \text{ hrs}} = 273.44 \text{ kW}.
 \end{aligned}$$

Power generation capacity of the Caterpillar engine = 0.27 MW

(3.21)

Also applying Equation 3.20 to the MCFC fuel cell we get:

$$\begin{aligned}
 PowerCapacity_{MCFC} &= 47\% \times \frac{3,412 \text{ kWh}}{Btu} \\
 &\times 101,745,000 \text{ BTU/day} \times \frac{1 \text{ day}}{24 \text{ hrs}} = 583.96 \text{ kW}.
 \end{aligned}$$

Power generation capacity of the MCFC fuel cell = 0.58 MW

(3.22)

### 3.2 Calculated Energy Content of Raw Manure, Digested Manure and Separated Digested Solids

As previously calculated in Equation 3.1, the farm produces 300,000 lbs of manure a day. Expressed in tons/day, the total raw manure slurry is

$$\begin{aligned} raw\ manure_{tons} &= manure_{lbs} \div 2,204\ lbs.kg^{-1} \\ &= 300,000\ lbs/day \div 2,204\ lbs.kg^{-1} \\ &= 136.12\ tons/day \end{aligned} \tag{3.23}$$

and the total solids (TS) content inside the raw manure is

$$\begin{aligned} raw\ manure_{TS} &= TS_{content} \times raw\ manure_{tons} \\ &= 13.3\% \times 136.12 = 18.10\ tons/day = 18,103.45\ kg/day \end{aligned} \tag{3.24}$$

The energy content of manure and other materials is described by the caloric value or heat value. That energy content is released through combustion of the material in oxygen or air. The units for caloric value is usually MJ/Nm<sup>3</sup> for gases, MJ/l for liquids or MJ/kg or kJ/kg for solids.<sup>59</sup> There are two forms for expressing energy content: the higher heating value (HHV) and lower heating value (LHV). The high heating value (HHV) is a measure of the energy (MJ/kg or BTU/lb) resulting from combustion of fuel samples (including manure and biosolids) with a calorimeter.<sup>60</sup> The low heating value (LHV) modifies the HHV by removing the latent heat of the water vapor formed during combustion of the fuel. The latent heat contained in water cannot be used to heat anything else therefore LHV is the best representation for available energy for subsequent uses and processes.<sup>59</sup>

Assuming raw manure<sub>LHV</sub> = 15.60 MJ/kg is the lower heating value for raw manure,<sup>61–65</sup> then the energy content of the total solids within the raw manure<sub>TS</sub>

is:

$$\begin{aligned}
raw\ manure_{energy\ content} &= raw\ manure_{LHV} \times raw\ manure_{TS} \\
&= 15.6\ MJ/kg \times 18,103.45\ kg/day \\
&= 282,413.82\ MJ/day = 3.2687\ MJ/s
\end{aligned} \tag{3.25}$$

Note that MW = MJ/s, therefore the required

energy content of the raw manure slurry = 3.27 MW LHV
---

Digested slurry loses some of the total solids(TS) content that is originally found in the raw slurry because biogas comes from destroyed biologically volatile solids (VS) which make up part of the original TS. Therefore the energy content of digested slurry is expected to be lower. Assume a 20% reduction of the energy content found in the raw slurry. That leaves

$$\begin{aligned}
digested\ slurry_{energy\ content} &= (1 - 20\%) \times 15.6\ MJ/kg \\
&= 12.32\ MJ/kg
\end{aligned} \tag{3.26}$$

in the digested slurry. Slurry produced from the digester effluent is given by:

$$\begin{aligned}
digested\ effluent\ slurry &= Manure_{Lbs} \times (1 - BV S_{destroyed}) \\
&= 300,000 \times (1 - 3.07\%) = 298,775\ lbs/day
\end{aligned} \tag{3.27}$$

Based on a moving coordinate model<sup>7,66</sup> and digester performance measurements,<sup>35</sup> 70% – 72% of the TS still remains in the effluent after digestion. Assuming 70.79%<sup>7,66</sup> is the undigested TS, then solids in the digested slurry is calculated as:

$$70.79\% \times 39,900\ lbs/day = 28,244\ lbs/day \tag{3.28}$$

From Equation 3.27, total digested slurry is

$$= 298,775\ lbs/day / 2,204\ lb.Ton^{-1} = 135.56\ tons/day.$$

From Equation 3.28, TS in the digested effluent is

$$= 28,244 \text{ lbs/day} / 2,204 \text{ lb.Ton}^{-1} = 12.815 \text{ tons/day}.$$

The energy content is

$$= 12,815 \text{ kg/day} \times 12.32 \text{ MJ/kg} = 157,879 \text{ MJ/day} = 1.8273 \text{ MJ/s}$$

The energy content of TS in digested slurry = 1.83 MW LHV
---

Screw press separators are assumed to be Vincent separator (Model No. K2-10) which remove around 50% of the solids<sup>67</sup> in a biosolids stream while 50% remains in the liquid stream. This gives us

$$\text{screw separated biosolids} = 50\% \times \text{solids in the digested slurry} \quad (3.29)$$

$$50\% * 28,244 = 14,122 \text{ lbs/day}$$

for the mass of separated biosolids produced daily. Note that these solids are not completely dry. The post-digester manure in fact, has a moisture content of about 70%.<sup>46</sup> Therefore, undried biosolids from screw separator is

$$\text{undried biosolids} = \text{screw separated biosolids} / (1 - \text{moisture content}) \quad (3.30)$$

$$14,122 / (1 - 70\%) = 47,073 \text{ lbs/day} = 21.36 \text{ tons/day},$$

and the liquids sent to the storage lagoon is

$$298,775 - 47,073 = 251,702 \text{ lbs/day} = 114.2 \text{ tons/day}.$$

Assuming 4.41 cubic yards per day of biosolids are made per 1,000 lbs of dry screw separated manure (based on measurements of effluent flow rate (lbs/min and ft<sup>3</sup>/min) in Gooch 2007<sup>35</sup>) then the volume of separated digested solids is

$$4.41 \text{ yd}^3 / 1000 \text{ lbs} \times 14,122 \text{ lbs/day} = 62,27 \text{ yd}^3 / \text{day}.$$

Because a screw press separator is used to separate the digested slurry into a 50:50 mix of solids and liquid effluent streams then 14,122 lbs/day (= 6.41 Tons/day = 6,407.50 kg/day) of the solid effluent is produced per day. With an energy content of 12.32 MJ/kg from equation 3.26, the energy content of the separated digested biosolids is then given by,

$$12.32 \text{ MJ/kg} \times 6.407.50 \text{ kg/day} \times 1\text{day}/(24\text{hr} \cdot 3600\text{s}) = 0.9136 \text{ MW LHV.}$$

Therefore,

energy content of the separated digested biosolids = 0.91 MW LHV,
---

and because the screw separator splits the its content 50:50, the

energy content sent to the storage pond/lagoon is = 0.91 MW LHV.
--

The material and energy flow diagrams for these calculations were programmed into spreadsheets and the resulting material and energy balances are shown in Figures 3.1 and 3.2. Spreadsheets like these can be used to assess the energy resource inventory for any size farm or digester site with a given quantity of input manure and organic waste.

### **3.3 Calculation Of Pure Methane For Storage And Mixed Tailgas For Local Cogeneration With A Fuel Cell**

To store pure methane before exporting it to natural gas pipelines or before my special case of onpeak power sales to the grid without the bulk of added CO<sub>2</sub> in stored product, the biogas must be purified. Typically this is done using a molecular sieve or a pressure swing adsorption system (PSA). in a sequence of steps. The PSA will remove the 2 major contaminants H<sub>2</sub>S step, as well as a CO<sub>2</sub>. I propose however, a 2-step removal process that first removes H<sub>2</sub>S from the biogas before purification of in a PSA system.

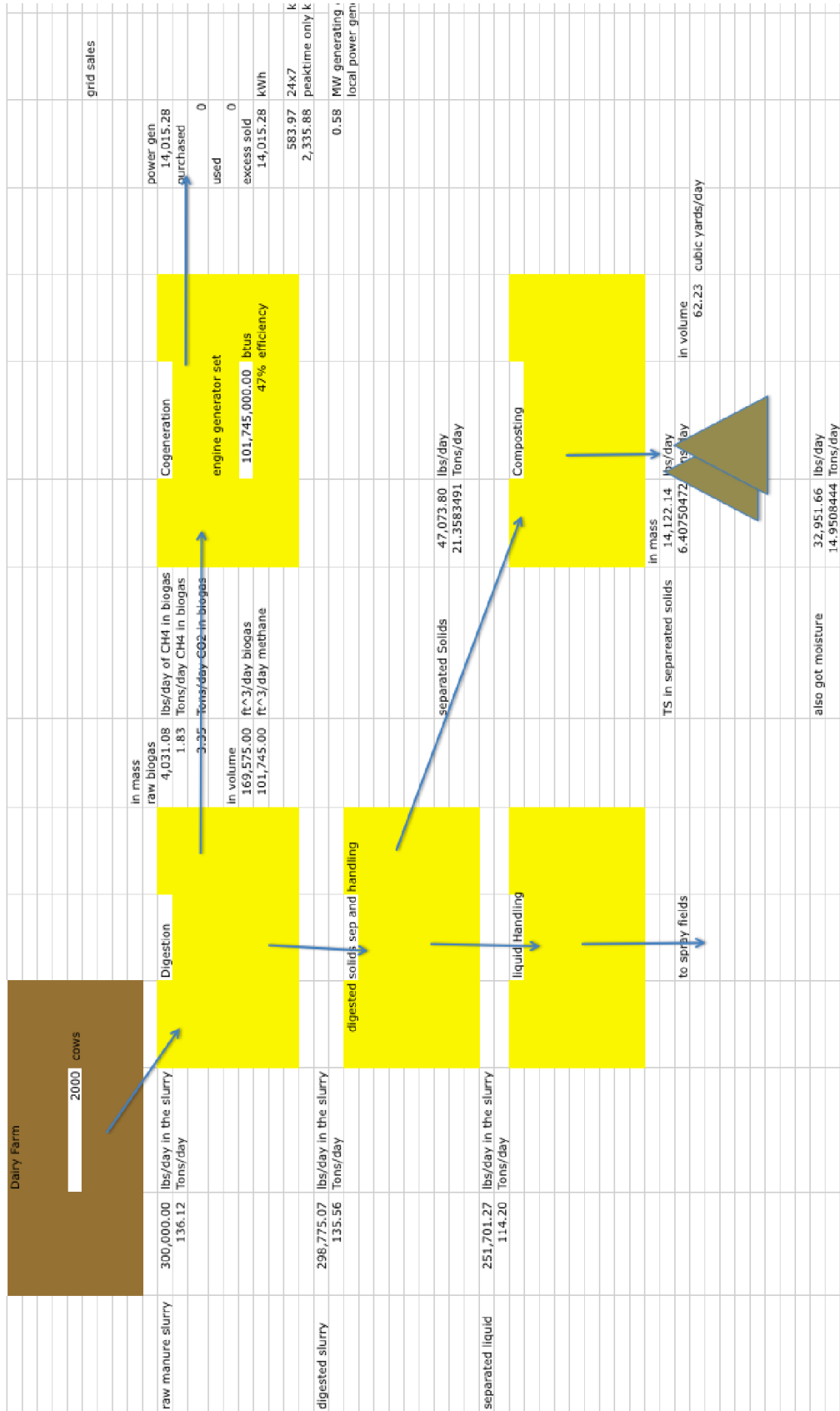


Figure 3.1: Material Balance in Metric Tons and lbs/day for a Net-Metered Generic 2,000 Milking Cow Dairy Farm with Anaerobic Digestion, On-Site Cogeneration, Liquid Solid Separation and Composting.

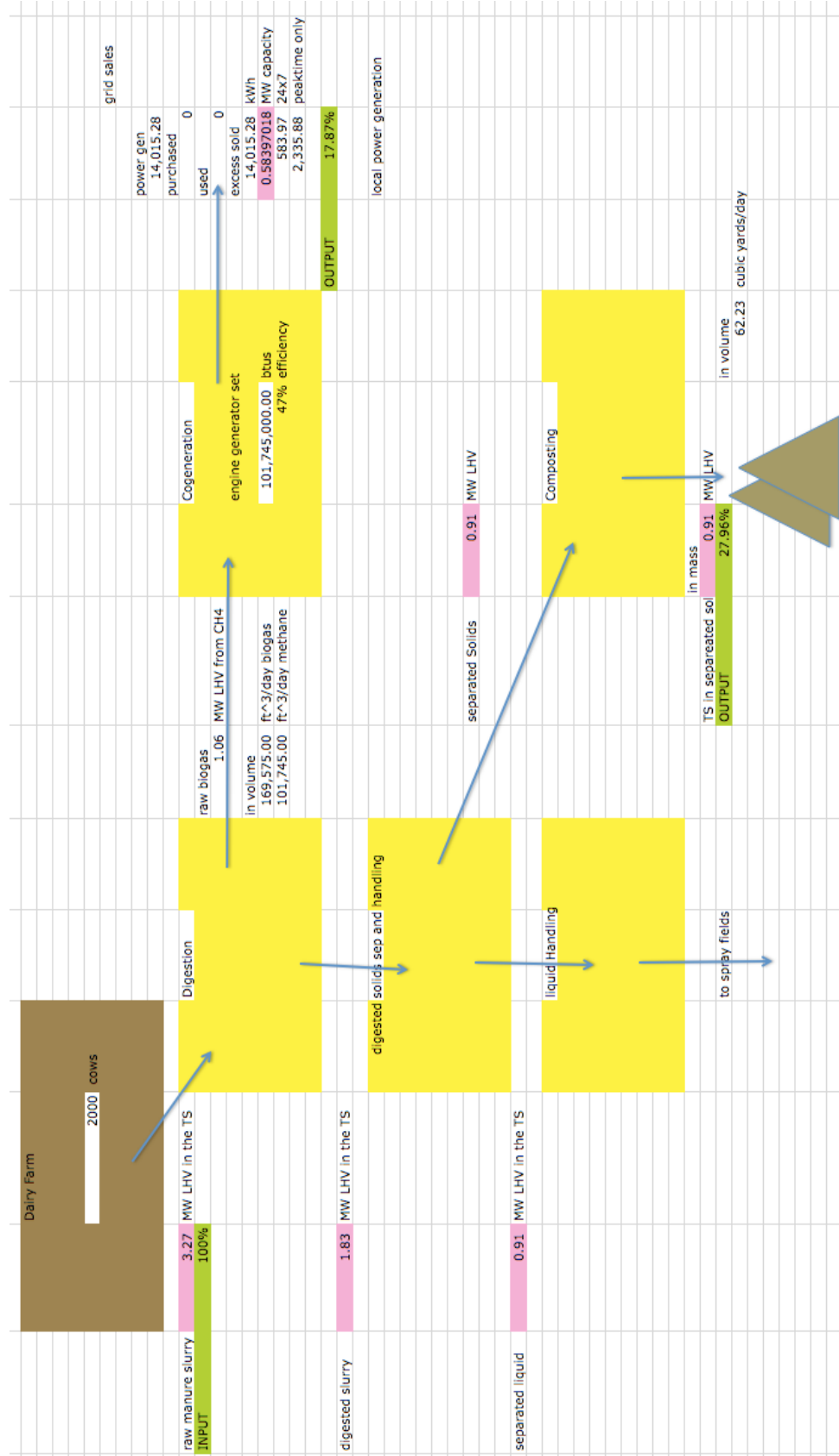


Figure 3.2: Energy Balance in Megawatts (MW) for a Net-Metered Generic 2,000 Milking Cow Dairy Farm with Anaerobic Digestion, On-Site Cogeneration, Liquid Solid Separation and Composting.

H<sub>2</sub>S, particulates and moisture can be removed from the biogas with a liquid scrubbing process or relatively inexpensively with either an iron sponge filter or an activated carbon filter. After removal of the very small fraction of H<sub>2</sub>S, biogas volume is assumed to be intact (in our example, at 169,575 ft<sup>3</sup>/day) unless gas fired compressors, which consume part of the biogas, are used. Assume electrical-driven compressors in this analysis. Subsequently, the molecular sieve would remove CO<sub>2</sub> and other contaminants resulting in the production of produces 99.9% pure methane for storage.<sup>68,69</sup> The tail gas (waste gas stream) effluent from this PSA is 18.5% methane and 82.5% CO<sub>2</sub>. Fifty-seven percent of the PSA product is the pure product gas stream and 42.23% is the tail gas stream.<sup>68,69</sup> This represents 2 energy streams, one high and the the other low for grid MCFC generated sales and on-site needs respectively. Adding pure methane to the tail gas flow in order to elevate the mixed tail gas' methane content to 43% CH<sub>4</sub> allows it to be used in an MCFC for on-site electricity needs. Thus, 31% of the pure methane stream is diverted from from storage to elevate the methane content of the tail gas.

From Equation 3.4 I estimated that 169,575 ft<sup>3</sup> of biogas is produced per day. In terms of standard cubic feet per minute, this is 117. 76 scfm. Thus the rate of pure methane storage is given by

$$\begin{aligned} \text{pure methane storage} &= \text{total biogas flow}_{cfm} \\ &\times \text{portion of } CH_4 \text{ designated for storage and grid sales} \end{aligned} \quad (3.31)$$

where total biogas flow = 169,575 ft<sup>3</sup>/day = 117.76 scfm. Therefore pure methane storage

$$\begin{aligned} &= 117.76 \text{ scfm} \times 57.77\% \times (1 - 31\%) \\ &= 117.76 \text{ scfm} \times 39.86\% = 46.94 \text{ scfm}, \end{aligned}$$



Pure methane flowrate for storage = 46.94 scfm
--

Also, mixed tail gas for continuous 24x7 local cogeneration with a MCFC fuel cell is found by the calculation:

$$\begin{aligned}
 \text{pure mixed tail gas} &= \text{total biogas flow}_{cfm} & (3.32) \\
 &\times (\text{tail gas} + \text{portion of } CH_4 \text{ designated for local cogen}) \\
 &= 117.76 \text{ scfm} \times (100\% \times (42.23\%) + 31\% \times (57.77\%)) \\
 &= 117.76 \text{ scfm} \times 60.14\% = 70.82 \text{ scfm}
 \end{aligned}$$

Mixed tail gas for continuous 24x7 local cogeneration = 70.82 scfm
--

At the calculated flow rate of 46.94 scf/min going into storage, a day's worth of methane production is given by

$$\begin{aligned}
 &24 \text{ hrs/day} \times 60 \text{ min/hr} \times 46.94 \text{ cf/min} \\
 &= 67,593.6 \text{ cf/day} = 1,916.869 \text{ m}^3/\text{day of pure methane}
 \end{aligned}$$

Thus, a standard 2,000m<sup>3</sup> storage tank would be adequate.

During the weekends and holidays, the time available to store pure methane continuously increases from 1 day up to two or three days [ie. Fri 7pm – Sat 7pm (1 day) – Sun 7pm (2 days) – Mon 7am (2.5 days) – Mon 7pm (3 days) – Tues 7am (3.5 days)]

Therefore, estimating the total storage required to store available pure methane depends on the dispatch schedule for consuming the gas in electricity generation. For,

$$1 \text{ day} = 1,916.9 \text{ m}^3/\text{day} \geq \text{one } 2,000 \text{ m}^3 \text{ tank}$$

2 days = 3,833.8 m<sup>3</sup>/day  $\geq$  two 2,000m<sup>3</sup> tanks

3 days = 5,750.7 m<sup>3</sup>/day  $\geq$  three 2,000m<sup>3</sup> tanks

3.5 days = 6,709.2 m<sup>3</sup>/day  $\geq$  four 2,000m<sup>3</sup> tanks (or one 6,000m<sup>3</sup> size + excess)

7.0 days = 13,418.4 m<sup>3</sup>/day  $\geq$  seven 2,000m<sup>3</sup> tanks (or two 6,000m<sup>3</sup> size + excess)

These calculations were programmed into spreadsheets and the resulting input output diagram is shown in Figure 3.3. It describes the designated PSA product and PSA coproduct to storage and local cogeneration for onsite needs.

### 3.4 Summary

Figure 3.4 summaries the system of converting biogas from a digester into two fuel streams: one high energy stream for on-peak cogeneration buffered by a gas storage system and a lower quality stream that uses the tailgas to supply on-site energy needs. This set-up differs from the typical methane production set-ups in two ways. First, a preliminary step that removes H<sub>2</sub>S ensures that both the methane and tailgas are suitable for use with a fuel cell. Secondly, the tailgas is enrich with pure methane and used as opposed to the current practise of simply releasing or flaring it off into the atmosphere.

Spreadsheet applications were also developed to incorporate the material and energy balance calculations performed in the previous sections of this chapter. Given the number of cows and efficiency of the generator system, the applications estimate how much methane can be produced, how much gas storage is required and how much energy can subsequently be produced from biogas. Figures 3.1 and 3.2 show the material and energy balance results for a generic dairy farm digester system with 2,000 milking cows.

An important observation from those energy inventories and material bal-

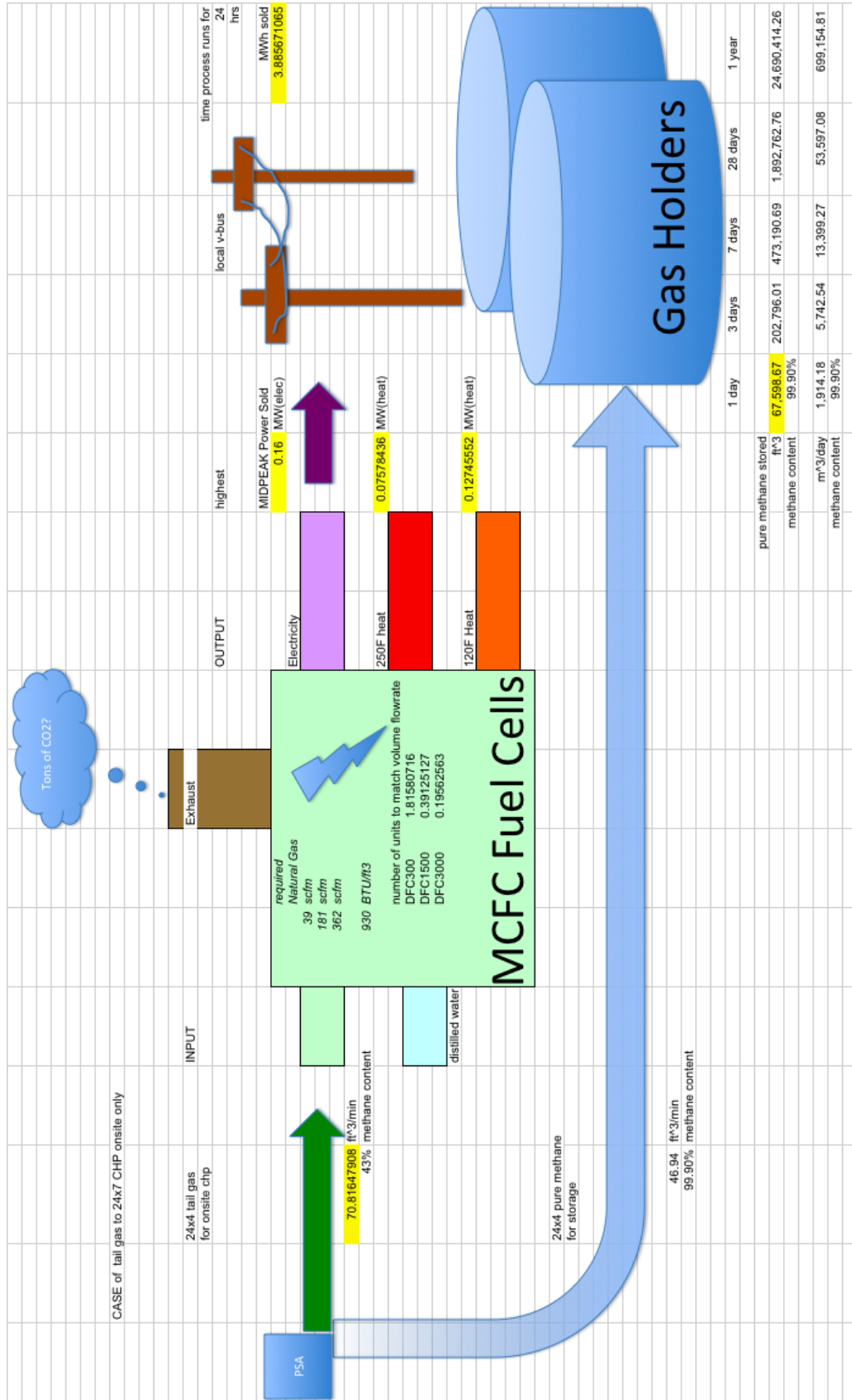


Figure 3.3: Purification of biogas into pure methane and tail gas fuel streams

Screenshot of spreadsheet program for illustration of pathway and calculation of pure methane and tail gas fuel streams for storage and on-site fuel generation for a generic 2,000 milking cow dairy digester site.

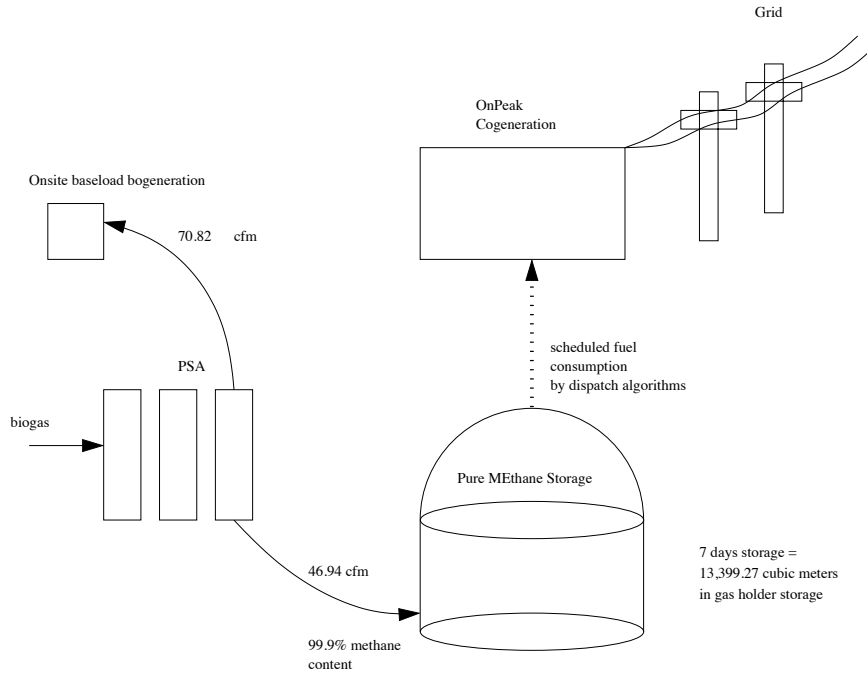


Figure 3.4: Two fuel streams from PSA to gas holder storage and onsite generation.

ance calculations is that electricity generation from biogas is only 1/12th (ie. 0.27MW/3.27MW) to 1/6th (ie. 0.58MW/3.27MW) of the total daily energy emerging from the digester depending on the type of generation technology utilized to convert the methane energy to electrical power. At the low end of the range is a diesel engine genset while the higher end of the range uses a molten carbonate fuel cell.

A little under a 1/3rd of the original energy content of the raw manure goes unused as a fuel and end up in the liquid pond. Similarly just under a 1/3rd of the original energy content of the raw manure goes unused as a fuel and winds up in the compostable digested manure piles. Coproducts that can be captured from the digested manure slurry would most likely double the power output and increase the storable energy energy from the digester site. Chemical or biological flocculation of the separated digested liquid would increase energy from all TS in the digester effluent.

By drying the biosolids to 10% moisture then pyrolysing the solids, it is possible to access more storable fuel from the digested waste in the form of biooil, biosyngas and biochar. DME can also be made from gasifying the resulting biooil, biosyngas as well as the CO<sub>2</sub> rich effluent from digester generator. The reader is encouraged to refer to the Appendix for more details about how thermochemical processes could help increase total resource recovery at digester sites.

Fast pyrolysis of the biosolids produces 65% biooil: 25% syngas: 10% biochar.<sup>70</sup> Prior to pyrolysis, the separated biosolids from Equation 3.30 must be dried down from 47,073 lbs/day to 10% moisture. This gives us bone dry biosolids = 14,122 lbs/day/10%= 15,691 lbs/day

Thus, biofuel production from pyrolysis is:

$$\text{biooil} = 65\% \times 15,691 = 10,199 \text{ lbs} = 4.63 \text{ tons/day}$$

$$\text{biochar} = 1,569 \text{ lbs/day} = 0.71 \text{ tons/day}$$

$$\text{syngas} = 3,923 \text{ lbs/day} = 1.78 \text{ tons/day}$$

$\text{Biooil production from digested biosolids} = 4.63 \text{ tons/day}$
--

Bio-oil can be used as a replacement for numerous applications where fuel oil is used or further reformed into syngas or processed into transportation fuels like biodiesel and DME.

Traditionally, digesters, covered lagoons etc on dairy farms have been used as a means to sequester manure, reduce odor and for nutrient management. Energy recovery from biogas was a welcome by-product. This chapter shows that manure is a significant energy resource. With proper incentives in place and an economically rewarding model for extracting that energy, energy recovery from farm wastes could play a sustainable role in achieving the goals for a primarily renewable energy smart grid.

## CHAPTER 4

### STATIC MODEL: REFILLING STORAGE VESSELS WITH PURIFIED METHANE TO TIME SHIFT ENERGY

#### 4.1 Introduction

A static model was developed and tested in this chapter in support of the dynamic model in Chapter 5. The system is illustrated by Figure 4.1 below. The intent is to model and simulate steady state production of pure methane for continuously refilling gas holder bags and tanks. The stored energy can then be used to increase electricity generator capacity and strategically time shift power sales to a few hours of onpeak times using quantities of fuel that is not possible when biogas comes directly from a digester.

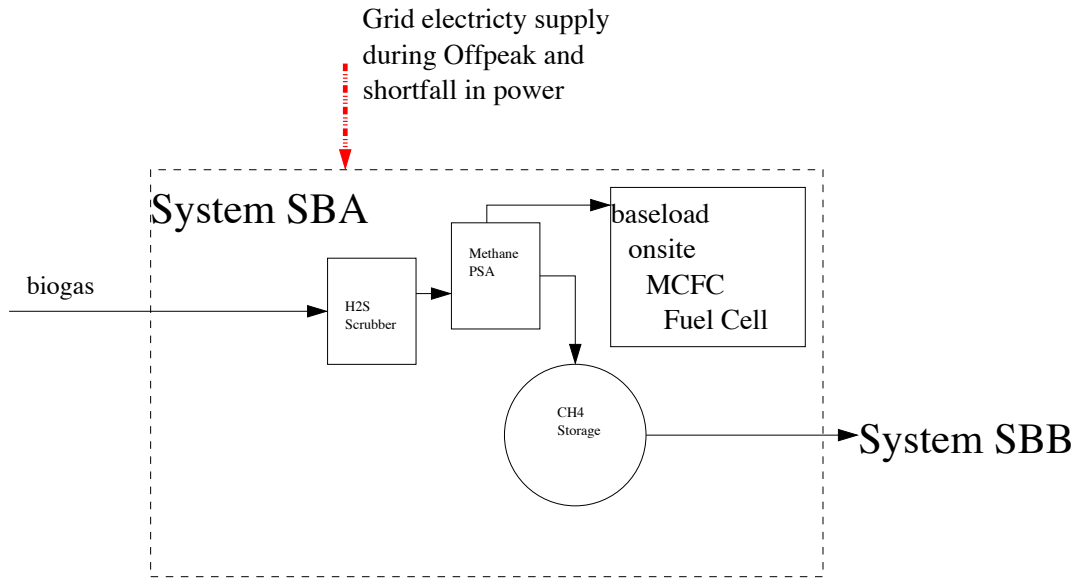


Figure 4.1: System SBA used to develop the static model. It simulates the consumption of biogas and the production of the methane gas that powers the electricity generator in system SBB.

Steady biogas production and storage can be simulated using a static network model that was first applied to ecosystems and agricultural production by

Koenig.<sup>71,72</sup> Network modelling and graph theory have been used to model the energy and mass balance equations of chicken production,<sup>73</sup> dairy farms<sup>74</sup> and soy-based biofuel-eco-industrial parks.<sup>75</sup> Those network network modelling and graph theory methods are also applicable to my energy storage model. The aim of this chapter is to size the gas holder bags to store purified methane within a system where continuous biogas consumption is the sole stimulus variable. In contrast, the stimulus variable in Chapter 5 is electricity dispatching to the wholesale grid which is not continuous but broken up into 4 hour time blocks (System SBB). The stored methane in the gas holders link the two systems because the quantity of stored fuel (in Millions of British thermal units or MMBtu) must meet the 1 MW capacity requirement for 4 or 8 hours per day electricity dispatching into the wholesale market.

## 4.2 Materials and Methods

### 4.2.1 Graphics and Terms Used in Network Models

Definitions of the terms used in network modelling<sup>72,74-76</sup> are essential to understanding the methods and results of this chapter of the dissertation. Take a look at the diagrams in Figure 4.2 (a) to (h) as I go through each type of graphical component used in a network model. The material type for a particular flow variable is always for the same type of material. For example, if y9 is used for CO<sub>2</sub>, then y9 only designates CO<sub>2</sub> flow in all diagrams. Flow variables are represented by directed arrows as in Figure 4.2 (a). The terms material, product and product quantity refer to the actual substances that flow through the flow variables. A process is defined as a point in the model where one product or material is converted into another product or material. Processes are sometimes referred to as

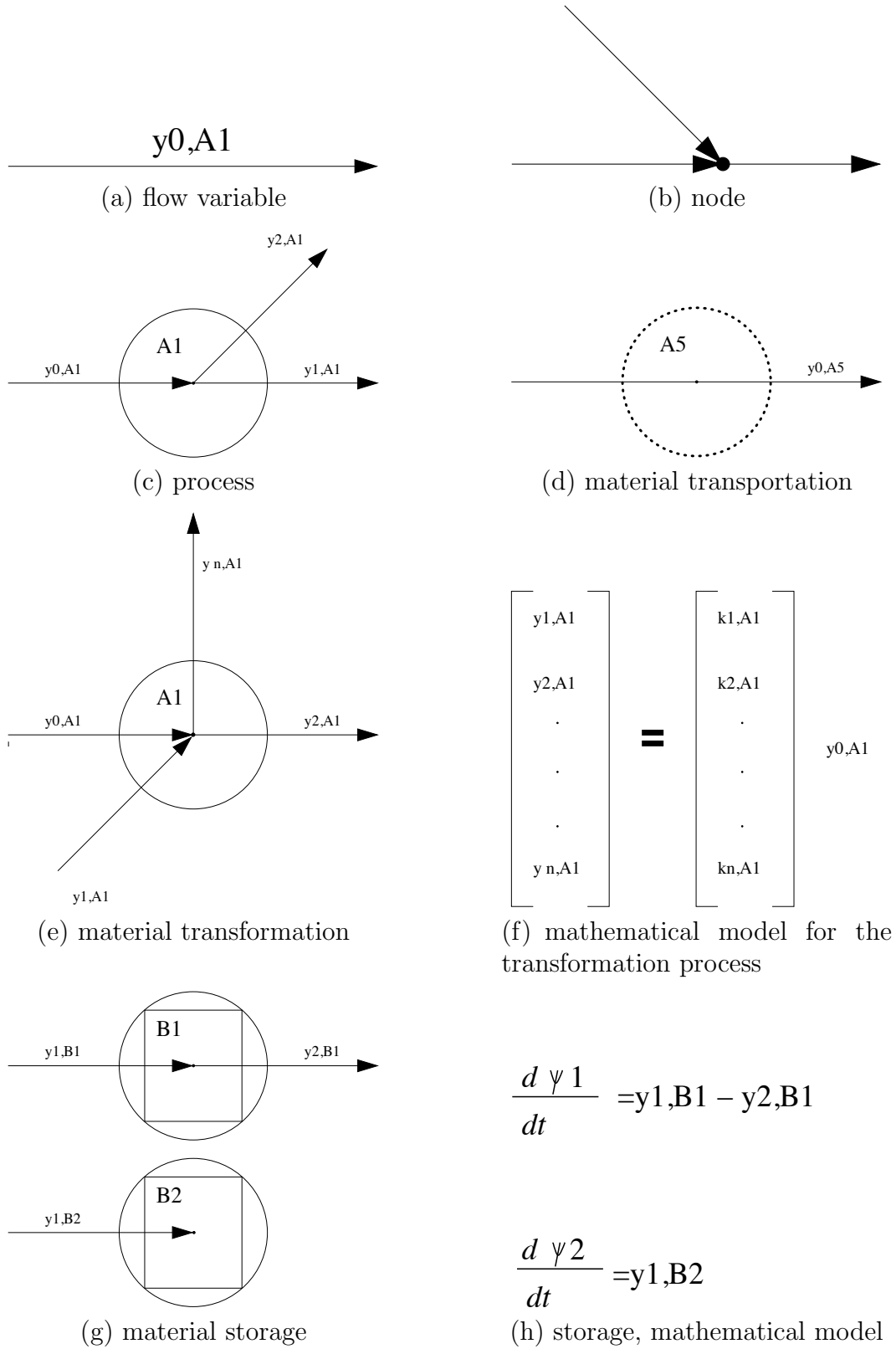


Figure 4.2: Description of the building blocks used in the network model



machines, facilities, converters, generators or industries. Labelled and numbered circles are used to represent processes as depicted in Figure 4.2 (c). There are different process categories including: material transformation processes, material transport processes, and material storage processes.<sup>72,77</sup> Dynamics systems, that denote rates of change of material in a process, are added to network modelling by adding storage.<sup>77</sup> A labelled and numbered square shape enclosed in a circle, see Figure 4.2 (g), is used to represent storage. Sometimes cylinders are used because they look like tanks and silos seen on farms.

A technology coefficient is defined as a constant number that converts one material into another at a process. They are represented by  $k_{i,j}$  values in this study where  $i$  identifies the flow variable attached to the process  $j$ . A capacity is defined as the upper limit that a flow variable can be or the maximum quantity that can be produced from a process. A node is a point where a flow variable can be separated into two or more streams for the conservation of mass and conservation of energy. A node is represented by a small point adjoining two or more directed arrows (Figure 4.2 (b)). The term market is used to describe the part of the system boundary where the inputs enter the system and outputs leave the system. It can be thought of as a destination or sink where products are traded or sold and revenue or expenses are paid.

### 4.2.2 Mathematical Methods Used in Network Models

Koenig's network modelling approach is applied to problems derive expressions in the form  $A \cdot x = b$  in order to find the solution to unknowns in vector  $x$ . Vector  $x$  is found using  $x = A' \cdot b$  where  $A'$  is the inverse of matrix of matrix  $A$ . This matrix method only works if a determinant of  $A'$  exists. If a determinant of  $A'$  does not exist then the network cannot be solved. With that matrix requirement, two

networks (1) a biogas demand driven system and (2) an electricity demand driven system, which are already known to be solvable, are later used as building blocks for a larger integrated system in our model.

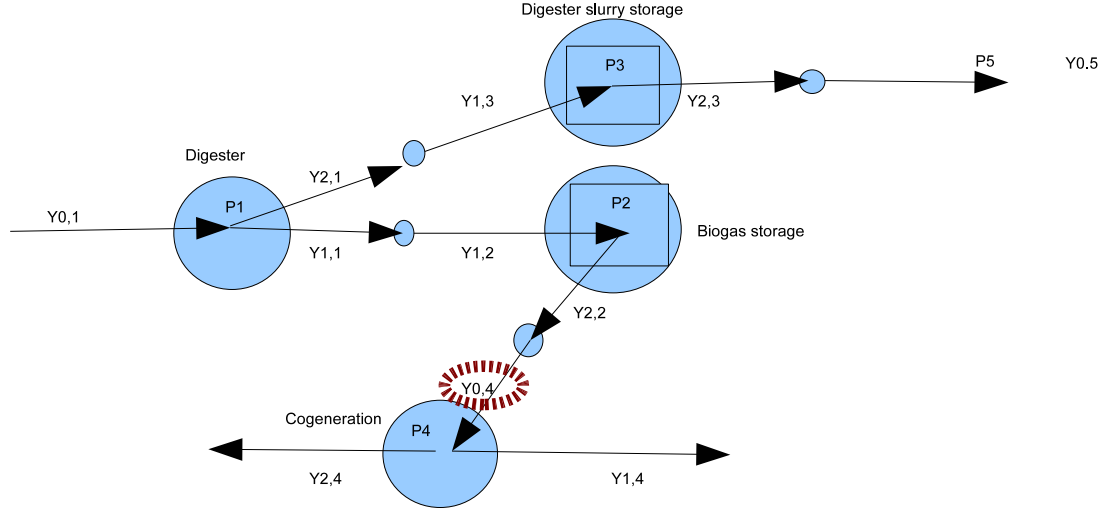


Figure 4.3: Biogas consumption driven network diagram for System SBA. It represents the transformation of manure, flowing into a digester, into biogas for immediate consumption and storage for later generation.

The diagram in Figure 4.3 represent a biogas facility with two material transformation processes, P1 and P4; and two material storage processes, P2 and P3. Focusing initially on graphical component P1, manure flows into the digester at P1 through flow variable  $y_{0,1}$  where  $y_{0,1}$  is the stimulus variable and  $y_{1,1}$  and  $y_{2,1}$  are the response variables. To derive the material flow equations, the outputs equal the associated technology coefficients multiplied by the input flow variable. For example, biogas output  $y_{1,1}$  equals technology coefficient  $k_{1,1}$  multiplied by the manure input  $y_{0,1}$ . For P1 the full set of material flow equations for biogas output, biogas storage and manure input are:

$$y_{1,1} = k_{1,1} \cdot y_{0,1} \quad (4.1)$$

$$y_{2,1} = k_{2,1} \cdot y_{0,1} \quad (4.2)$$

$$y_{0,1} = y_{1,1} + y_{2,1} \quad (4.3)$$

\*\*\*

There is another energy cost equation involving the same technology coefficients  $k_{i,j}$  that Koenig uses for each process, however, that is not utilized at this level of analysis. That equation is:

$$x_{0,1} = -k_{1,1} \cdot x_{1,1} - k_{2,1} \cdot x_{2,1} - f(y_{0,1}) \quad (4.4)$$

where  $x_{i,j}$  are energy costs for associated with each flow variable and the  $f()$  function is reserved for any non-linear economies of scale considerations.

\*\*\*

Mathematically, we want to solve the whole network model using the format

$$A \cdot x = b \quad (4.5)$$

shown in Equation 4.6 where technical coefficients matrix,  $A$ , multiplied by vector of flow variables,  $x$ , is equal to the vector of known input-output quantities,  $b$ .

$$\begin{bmatrix} \frac{1}{k_{(1,1)}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{k_{(2,1)}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -1 & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(1,4)}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(2,4)}} \end{bmatrix} \cdot \begin{bmatrix} y_{1,1} \\ y_{2,1} \\ y_{1,3} \\ y_{2,3} \\ y_{1,2} \\ y_{2,2} \\ y_{1,4} \\ y_{2,4} \end{bmatrix} = \begin{bmatrix} y_{0,1} \\ y_{0,1} \\ 0 \\ y_{0,5} \\ 0 \\ y_{0,4} \\ y_{0,4} \\ y_{0,4} \end{bmatrix} \quad (4.6)$$

This A.x=b matrix equation is the same thing as the following 8 inputoutput linear equations:

$$y_{1,1} = k_{1,1} * y_{0,1}$$

$$y_{2,1} = k_{2,1} * y_{0,1}$$

$$y_{1,2} = y_{1,1}$$

$$y_{1,3} = y_{2,1}$$

$$y_{2,3} = y_{0,5}$$

$$y_{2,2} = y_{0,4}$$

$$y_{1,4} = k_{1,4} * y_{0,4}$$

$$y_{2,4} = k_{2,4} * y_{0,4}$$

In addition, storage of biogas in P2 and storage of digester slurry in P3 are defined by the two rate equations:

$$d\psi_2/dt = y_{1,2} - y_{2,2} = k_{1,1} * y_{0,1} - y_{0,4}$$

$$d\psi_3/dt = y_{1,3} - y_{2,3} = k_{2,1} * y_{0,1} - y_{0,5}$$

and:

$\psi_{2(t=0)}$  = initial volume of the biogas storage tank

$\psi_{3(t=0)}$  = initial mass of manure in the slurry tank

Thus we now have:

3 knowns  $y(0,1)$ ,  $y(0,4)$ ,  $y(0,5)$ ;

10 unknowns  $y(1,1)$ ,  $y(2,1)$ ,  $y(1,3)$ ,  $y(2,3)$ ,  $y(1,2)$ ,  $y(2,2)$ ,  $y(1,4)$ ,  $y(2,4)$ ,  $\psi_2$ ,  $\psi_3$ .

Assuming initial volumes of manure and biogas instorage = 0, a solution can be found for the vector  $x$ , given data from a generic digester site as follows:  $y_{0,1}$  = 90,000 lbs/day of raw manure slurry,

$y_{0,4}$  = 43,000 cubic feet of biogas per day to run the engine generator set (genset),

$y_{0,5}$  = 86,704 lbs/day of degassed slurry,

$\psi_2(t = 0) = 0$ , and

$\psi_3(t = 0) = 0$  storage capacity.

The problem was programmed into GNU Octave and the vector of unknowns  $x$  was solved by  $A \cdot b = x$  in the steps shown by the following output:

---

---

```
octave -3.2.3:30> biogas_driven_network_AADairy
```

```
How many pounds of manure to add to the digester? 90000
```

```
How many cubic feet of biogas required by genset? 43000
```

```
y0_1 = 90000
```

```
y0_4 = 43000
```

```
y0_5 = 86704
```

```
System coefficient matrix, A=[
```

```
  1/k1_1  0      0 0 0 0 0      0
  0      1/k2_1  0 0 0 0 0      0
  0      -1      1 0 0 0 0      0
  0      0      -1 1 0 0 0      0
 -1      0      0 0 1 0 0      0
  0      0      0 0 0 1 0      0
  0      0      0 0 0 0 1/k1_4  0
  0      0      0 0 0 0 0      1/k2_4
```

```

]

k1_1=13.3/100*85/100*5
k2_1=1-13.3/100*(11.15-8.08)/11.15;
k1_3=1;
k2_3=1;
k1_2=1;
k2_2=1;
%to get in MW capacity for old genset
k1_4=.60*930/1000000*.22/3.142/24;
%to get in MMBtu_hotwater per hour from old genset
k2_4=.60*930/1000000*.43/24;

therefore A=[
    1.769129          0          0 0 0 0      0          0
    0          1.038012      0 0 0 0      0          0
    0          -1.000000      1 0 0 0      0          0
    0          0          0 1 0 0      0          0
    -1          0          0 0 1 0      0          0
    0          0          0 0 0 1      0          0
    0          0          0 0 0 0      6.1427e+05      0
    0          0          0 0 0 0      0          1.0003e+05
]

det_A = 1.1283e+11
Determinate of A = 112831616851.00363159

b =
    90000
    90000
     0
    86704
     0
    43000
    43000
    43000

x =
    5.0872e+04
    8.6704e+04
    8.6704e+04
    8.6704e+04
    5.0872e+04
    4.3000e+04
    7.0002e-02
    4.2989e-01

```

---

Interpreting the solved vector x, we have:

$y_{1,1} = 50,872$  cubic feet of biogas per day produced by the digester,

$y_{2,1} = 86,704$  lbs of digester slurry per day leaves the digester as effluent,  
 $y_{1,3} = 86,704$  lbs of digester slurry per day is pumped to the slurry tank for storage,  
 $y_{2,3} = 86,704$  lbs of digester slurry per day is pumped from the slurry tank to help fertilize the soil,  
 $y_{1,2} = 50,872$  cubic feet of biogas per day used to refill the gas holder storage,  
 $y_{2,2} = 43,000$  cubic feet of biogas per day consumed from the stored biogas,  
 $y_{1,4} = 0.07\text{MW}$  or  $70 \text{ kW}$  of power capacity from the old genset, and  
 $y_{2,4} = 0.43 \text{ MMBtu}$  per day of recoverable heat is available from electricity generation.

Notice that the refill rate exceeds the daily consumption by over 7,000 cubic feet ( $50,872 - 43,000$  cubic feet). In general, digester sites deal with excess fuel by flaring to reduce potential greenhouse gas effects.

The same method can be used to solve the problem when the generator input is in watts instead of biogas consumption. In this case, the system, reproduced in Figure 4.4 is described as electrically driven instead of consumption driven. Proceeding as before, we want to solve an equation of the form  $A \cdot x = b$ , where technical coefficients matrix,  $A$ , multiplied by vector of flow variables,  $x$ , is equal to the vector of known input-output quantities,  $b$ .

Mathematically, the network is described by the following matrix expression in Equation 4.7 which has the same vector  $x$  as in Equation 4.6 but slightly different arrangements in the coefficient matrix and  $b$  vector (to account for genset coefficients such as conversion efficiency, etc):

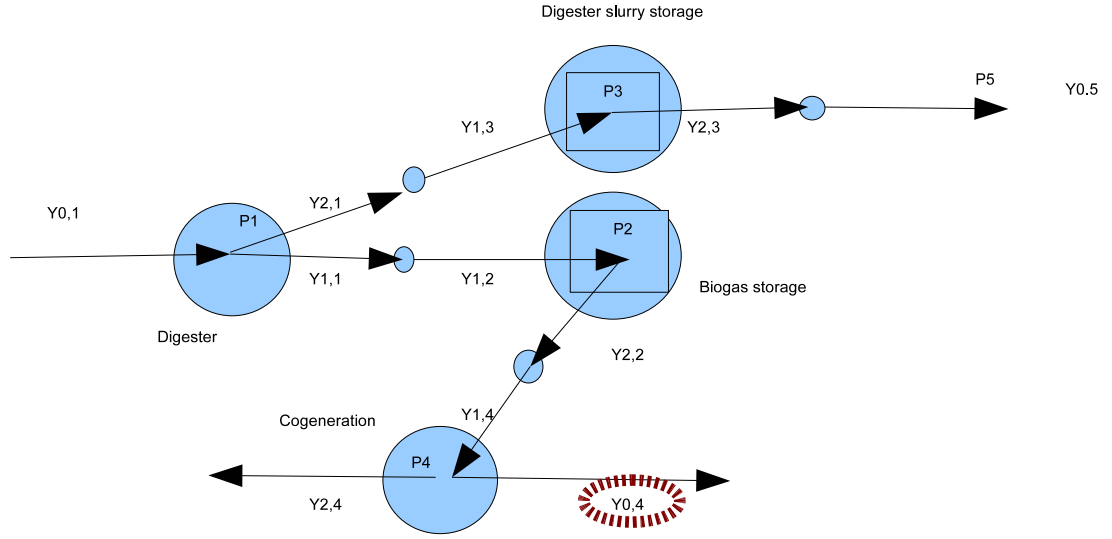


Figure 4.4: Electric power driven network diagram

$$\begin{bmatrix} \frac{1}{k_{(1,1)}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{k_{(2,1)}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & -1 & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & -1 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(1,4)}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(2,4)}} \end{bmatrix} \cdot \begin{bmatrix} y_{1,1} \\ y_{2,1} \\ y_{1,3} \\ y_{2,3} \\ y_{1,2} \\ y_{2,2} \\ y_{1,4} \\ y_{2,4} \end{bmatrix} = \begin{bmatrix} y_{0,1} \\ y_{0,1} \\ 0 \\ y_{0,5} \\ 0 \\ 0 \\ y_{0,4} \\ y_{0,4} \end{bmatrix} \quad (4.7)$$



That  $A.x=b$  equation is the same thing as these 8 input output linear equations:

$$y_{1,1} = k_{1,1} * y_{0,1}$$

$$y_{2,1} = k_{2,1} * y_{0,1}$$

$$y_{1,2} = y_{1,1}$$

$$y_{1,3} = y_{2,1}$$

$$y_{2,3} = y_{0,5}$$

$$y_{2,2} = y_{1,4}$$

$$y_{1,4} = k_{1,4} * y_{0,4}$$

$$y_{2,4} = k_{2,4} * y_{0,4}$$

Once again there are 3 knowns  $y_{0,1}$ ,  $y_{0,4}$ ,  $y_{0,5}$

10 unknowns  $y_{1,1}$ ,  $y_{2,1}$ ,  $y_{1,3}$ ,  $y_{2,3}$ ,  $y_{1,2}$ ,  $y_{2,2}$ ,  $y_{1,4}$ ,  $y_{2,4}$ ,  $\psi_2$ ,  $\psi_3$

Furthermore storage  $\psi_2$  of biogas in P2 and storage  $\psi_3$  of digester slurry in P3 are found by solving the rate equations:

$$d\psi_2/dt = y_{1,2} - y_{2,2} = k_{1,1} * y_{0,1} - k_{1,4} * y_{0,4}$$

$$d\psi_3/dt = y_{1,3} - y_{2,3} = k_{2,1} * y_{0,1} - y_{0,5}$$

and:

$\psi_{2(t=0)}$  = initial volume of the biogas storage tank

$\psi_{3(t=0)}$  = initial mass of manure in the slurry tank

The electricity driven model was programmed with values from the same generic digester site and a 130 kW power capacity genset:

$y_{0,1} = 90,000$  lbs/day of raw manure slurry,  
 $y_{0,4} = 130$  kW capacity from a engine generator set,  
 $y_{0,5} = 86,704$  lbs/day of degassed slurry, and  
 $\psi_2(t = 0) = 0$ , and  
 $\psi_3(t = 0) = 0$  storage capacity.

The vector of unknowns  $x$  is solved by  $A' \cdot b = x$  in the following steps by GNU Octave.

---

```

How many pounds of manure to add to the digester? 90000
How many MW generation for dispatching to the grid? 0.13
y0_1 = 90000
y0_4 = 0.13000
y0_5 = 86704
k1_1 = 0.56525
System coefficient matrix, A=[
  1/k1_1  0      0 0 0 0 0      0
  0      1/k2_1  0 0 0 0 0      0
  0      -1      1 0 0 0 0      0
  0      0      -1 1 0 0 0      0
-1      0      0 0 1 0 0      0
  0      0      0 0 0 1 -1     0
  0      0      0 0 0 0 1/k1_4  0
  0      0      0 0 0 0 0      1/k2_4
]

therefore A=[
  1.769129      0      0 0 0 0 0      0
  0      1.038012      0 0 0 0 0      0
  0      -1.000000      1 0 0 0 0      0
  0      0      0 1 0 0 0      0
-1      0      0 0 1 0 0      0
  0      0      0 0 0 1 -1     0
  0      0      0 0 0 0 0.000002  0
  0      0      0 0 0 0 0      0.149950
]
det_A = 4.4828e-07
Determinate of A = 0.00000045

b =
  9.0000e+04
  9.0000e+04
  0.0000e+00
  8.6704e+04
  0.0000e+00
  
```

```

0.0000e+00
1.3000e-01
1.3000e-01

x =
5.0872e+04
8.6704e+04
8.6704e+04
8.6704e+04
5.0872e+04
7.9855e+04
7.9855e+04
8.6696e-01

```

---

The interpretation of vector  $x$  is:

$y_{1,1}$  = 50,872 cubic feet of biogas per day produced by the digester,  
 $y_{2,1}$  = 86,704 lbs of digester slurry per day leaves the digester as effluent,  
 $y_{1,3}$  = 86,704 lbs of digester slurry per day is pumped to the slurry tank for storage,  
 $y_{2,3}$  = 86,704 lbs of digester slurry per day is pumped from the slurry tank to help fertilize the soil,  
 $y_{1,2}$  = 50,872 cubic feet of biogas per day used to refill the gas holder storage,  
 $y_{2,2}$  = 79,855 cubic feet of biogas per day consumed from the stored biogas,  
 $y_{1,4}$  = 79,855 cubic feet of biogas per day consumed by the old genset to meet local demand, and  
 $y_{2,4}$  = 0.87 MMBtu per day of recoverable heat is available from electricity generation.

Notice this time that the refill rate of the gas holder cannot meet the daily consumption by a shortfall of almost 30,000 cubic feet (79,855 - 50,872 cubic feet). In this case the genset could be run at around 60% of its rated power generation capacity. Alternatively, the engine could run for fewer hours than 24 hours per day or extra fuel can be added from some other source like a propane tank in order to run at full capacity.

### 4.3 Applying Methods to the Gas Holder Storage System

Those 2 previous network examples show that there is a pattern for solving unknowns  $x$  in a network that we can utilize for storage and rate change equations. Features of both of them are used as fuel consumption and electricity dispatching building blocks. Three of such building block networks (Figure 4.5) were integrated in order to find a solution to the pure methane storage and refilling rate from a digester site that would satisfy NYISO's required 1 MW minimum electricity generating capacity for participation in the wholesale electricity market. A mathematical framework was setup to first derive and solve the matrix form of the problem as described for the smaller systems. The system of differential equations are solved next and the results are interpreted in the subsequent discussion section. As shown Figure 4.5 the model, at its simplest, consists of an electrical demand driven part, module 2, and two fuel consumption driven parts, modules 1 and 3. Module 1 is used to simulate conversion of raw manure into digested biosolids  $y_{0,A1}$ , a low BTU mixture of tailgas for onsite generation  $y_{3,D3}$ , and a pure CH<sub>4</sub> stream  $y_{2,D2}$ . Module 2 is the simulation of pure methane refilling gas holder tank storage (flow variable  $y_{1,B2}$  going into cylinder  $\psi_3$  in Figure 4.5) followed by consumption of a portion of the stored methane for electricity dispatching to the grid (flow variable  $y_{0,B4}$ ) according to a pre-set dispatch schedule that will be discussed later. Module 3 is the simulation of tailgas consumption. Note that this is where I take advantage of a molten carbonate fuel cell's ability to run on waste gas supplemented with a modest amount of pure methane. This is an added benefit that is not possible with any other biogas electricity generation technology.

The model in Figure 4.5 can be significantly simplified. The material processes of A5, B5 and C5 represent material transport of biosolids and slurry left after biogas and methane production that are not relevant to electricity generation and

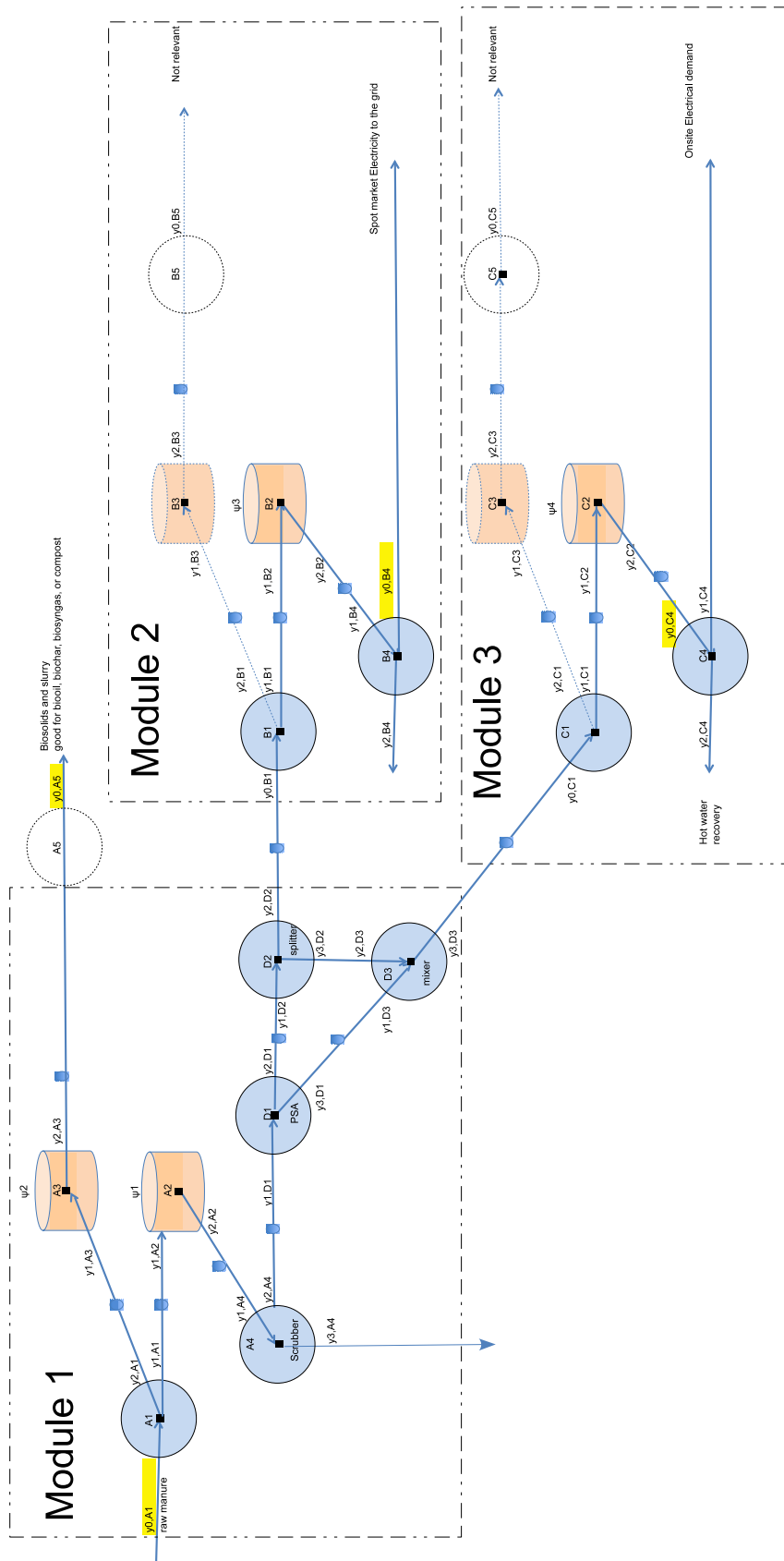


Figure 4.5: Three modules combined to derive the a new network model for methane production, storage, onsite generation and onpeak wholesale grid dispatching

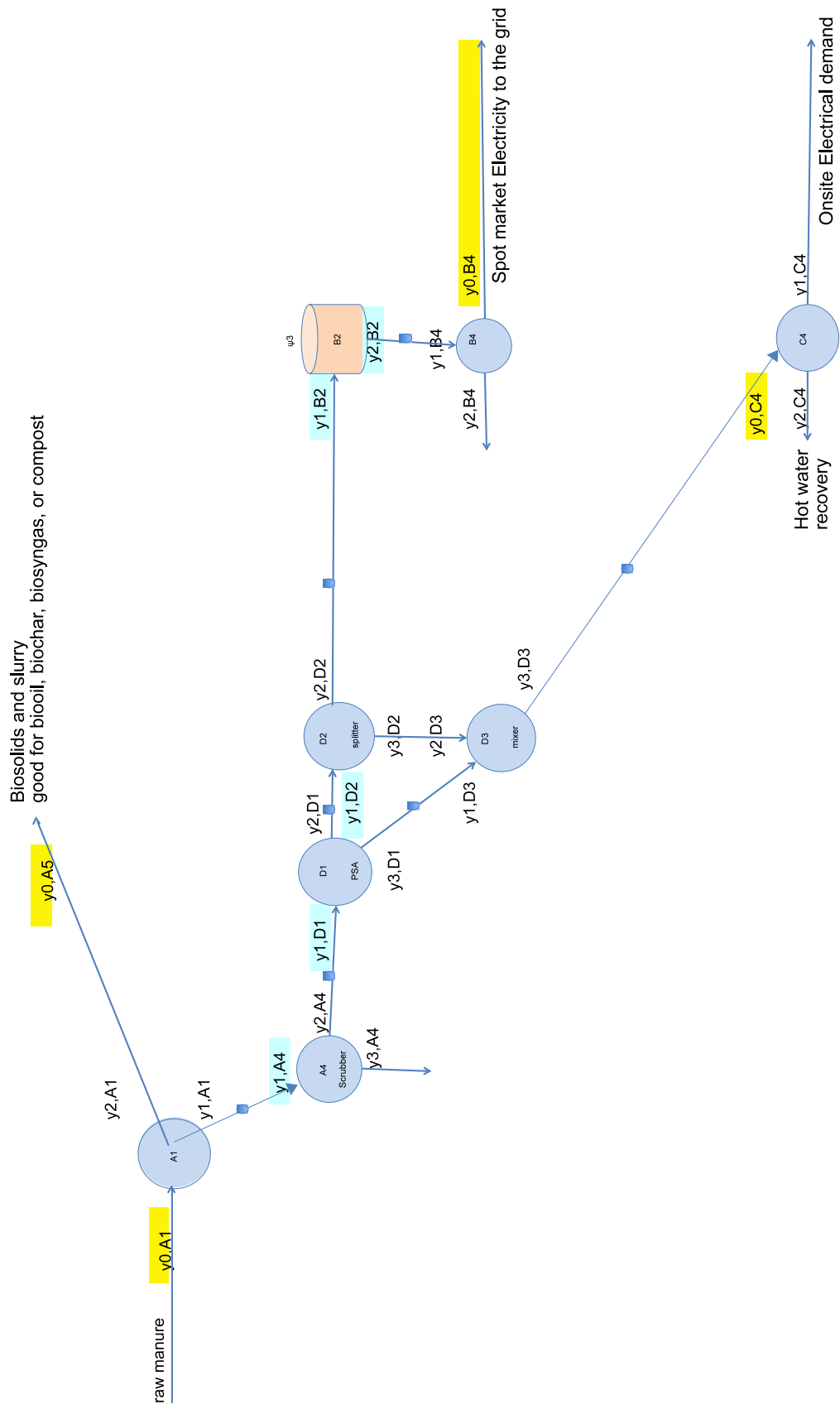


Figure 4.6: Network diagram used to derive the closed form model

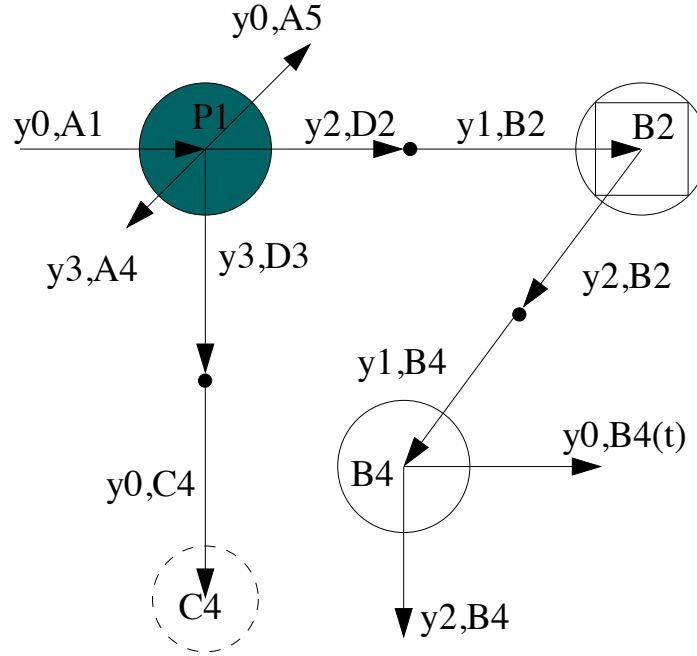


Figure 4.7: Simplified network diagram integrating the grid cogen and local cogen modules

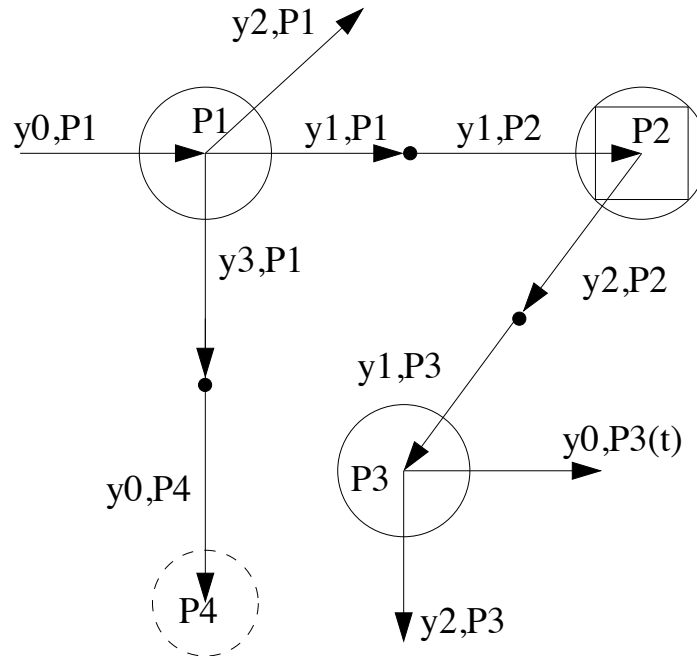


Figure 4.8: Pure methane gas holder storage network diagram

consumptions. Processes that are duplicated in the individual modules can be also be combined. D2 and B1, for example, both represent the process of pure methane production and can be combined. Figure 4.5 is thus simplified to the one shown in Figure 4.6.

Further simplification in a similar manner gives us Figure 4.7 and Figure 4.8 which is a computer executable model. It has 3 nodes, 2 material transformation processes P1 and P3; 1 storage process , P2, and 1 material transport process P4. With the simplified model, I am now able to set up a system of equations to solve for gas holder size and refill rate required to satisfy a given generation capacity.

Mathematically we want to solve  $A \cdot x = b$  shown in Equation 4.8 where the technology coefficients matrix A, multiplied by vector of flow variables, x, is equal to the vector of known input-output quantities, b.

$$\begin{bmatrix} \frac{1}{k_{(1,P1)}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{k_{(2,P1)}} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{1}{k_{(3,P1)}} & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & -1 & 0 \\ 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(1,P3)}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(2,P3)}} \end{bmatrix} \cdot \begin{bmatrix} y_{1,P1} \\ y_{2,P1} \\ y_{3,P1} \\ y_{1,P2} \\ y_{2,P2} \\ y_{1,P3} \\ y_{2,P3} \end{bmatrix} = \begin{bmatrix} y_{0,P1} \\ y_{0,P1} \\ y_{0,P1} \\ 0 \\ 0 \\ y_{0,P3} \\ y_{0,P3} \end{bmatrix} \quad (4.8)$$



this is the same as the following 7 equations:

$$y_{1,P1} = k_{1,P1} \cdot y_{0,P1}$$

$$y_{2,P1} = k_{2,P1} \cdot y_{0,P1}$$

$$y_{3,P1} = k_{3,P1} \cdot y_{0,P1}$$

$$y_{1,P2} = y_{1,P1}$$

$$y_{2,P2} = y_{1,P3}$$

$$y_{1,P3} = k_{1,P3} \cdot y_{0,P3}$$

$$y_{2,P3} = k_{2,P3} \cdot y_{0,P3}$$

There are 2 knowns  $y_{0,P1}$ ,  $y_{0,P3}(t)$

and 8 unknowns  $y_{1,P1}$ ,  $y_{2,P1}$ ,  $y_{3,P1}$ ,  $y_{1,P2}$ ,  $y_{2,P2}$ ,  $y_{1,P3}$ ,  $y_{2,P3}$ ,  $\psi_2$

where:

$y_{0,P1}$  = constant manure input,

$y_{0,P3}(t)$  = generator capacity \* an on/off power grid dispatching variable

From the simplified network model in Figure 4.8, the storage quantity in gas holder P2, also called  $\psi_2$ , is the volume of methane fuel inside the gas holder storage tanks. The storage quantity  $\psi_2$  is derived by solving the following rate equation:

$$\frac{d\psi_2}{dt} = y_{1,P2} - y_{2,P2} \quad (4.9)$$

such that  $\frac{d\psi_2}{dt}$  equals fuel refill rate to add fuel to the gas holder storage minus consumption of fuel from that storage. Those flow variables  $y_{1,P2}$  and  $y_{2,P2}$  are calculated from technology coefficients and the two known stimulus variables  $y_{0,P1}$  and  $y_{0,P3}(t)$  in Equation 4.8 and Figure 4.8. To get the full set of technology coefficients we have to look at previous flow variables and technology coefficients inside the unsimplified version of the networks in Figures 4.5 and 4.6. The source for all

the technology constants used in this chapter come from Table 3.1 in Chapter 3.

### Refill Rate, $y_{1,P2}$

On the right hand side (RHS) of Equation 4.9, the first term is a flow variable  $y_{1,P2}$  called the fuel refill rate. The fuel refill rate  $y_{1,P2}$  (equal to  $y_{1,P1}$ ) is the product of the technology coefficient  $k_{1,P1}$  and the manure input flow rate  $y_{0,P1}$ . In short,

$$\begin{aligned} y_{1,P2} &= k_{1,P2} * y_{0,P1} \\ &= k_{1,P1} * y_{0,P1} \end{aligned}$$

The flow variable  $y_{1,P2}$  is equivalent to  $y_{1,B2}$  in Figures 4.6 and 4.7. The refill rate  $y_{1,B2}$  from a digester site would be:

$$\begin{aligned} y_{1,B2} &= y_{2,D2} \\ &= y_{1,D2} - y_{3,D2} \\ &= y_{2,D1} - y_{3,D2} \\ &= [y_{1,D1} - y_{3,D1}] - y_{3,D2} \\ &= [y_{2,A4} - y_{3,D1}] - y_{3,D2} \\ &= [(y_{1,A4} - y_{3,A4}) - y_{3,D1}] - y_{3,D2} \\ &= [(y_{1,A1} - y_{3,A4}) - y_{3,D1}] - y_{3,D2} \\ &= k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{3,D1}) * (1k_{3,D2}) * y_{0,A1} \\ &= P * y_{0,A1} \end{aligned}$$

Using  $y_{0,P1}$  equivalent to  $y_{0,A1}$  in Figure 4.6 and using P to represent  $k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{3,D1}) * (1k_{3,D2})$

we get

$$y_{1,P2} = P * y_{0,P1}$$

P is found by

$$y_{0,A1} = N \text{ cows} * 150 \text{ lbs manure/milking cow/day (Table 3.1, coefficient a).}$$

$$k_{1,A1} = TS * VS * 5 \text{ lbs/day/cow} = \text{biogas yield per pound of raw manure (Table 3.1, coefficients b,c,e).}$$

$$= 13.3\% * 85\% * 100 * 5$$

$$= 0.565 \text{ ft}^3/\text{lb}$$

$k_{3,A4} = 0.05\%$  = portion of the raw biogas volume flow rate that is adsorbed by iron sponge and other scrubbing processes in order to remove all  $H_2S$  and impurities (Table 3.1, coefficient j).

$k_{3,D1} = 42.2\%$ , portion of the scrubbed biogas volume flow rate per day that becomes tailgas  $\text{ft}^3/\text{day}$  containing 18.5% methane content (Table 3.1, coefficient s)

$k_{3,D2} = 31\%$ , portion of the pure methane volume flow rate that is mixed with tailgas to make it 42% methane content (Table 3.1, coefficient q).

and finally:

$$P = k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{3,D1}) * (1 - k_{3,D2}) \quad (4.10)$$

$$= 0.56525 \text{ ft}^3/\text{lb} * (1 - 0.05\%)(1 - 42.2\%)(1 - 31\%) \quad (4.11)$$

For our example, we model a generic 2,000 cow dairy, so, we have

$$\begin{aligned}
y_{1,P2} &= P * y_{0,P1} \\
&= 0.56525 \text{ ft}^3/\text{lb} * (1 - 0.05\%)(1 - 42.2\%)(1 - 31\%) * 2,000 \text{ cows} * 150 \text{ lbs/cow/day} \\
&= 67,565.11 \text{ ft}^3 \text{ methane refill/day} \\
&= 2,815.21 \text{ ft}^3/\text{hour} \\
&= 46.92 \text{ cfm} \\
&= 1,913.23 \text{ m}^3 \text{ CH}_4 \text{ refill/day} \\
&= 79.72 \text{ m}^3/\text{hour} \\
&= 1.33 \text{ m}^3/\text{minute}
\end{aligned}$$

Thus the gas holder tank on the dairy digester site would be restocked at a refill rate of 79.72 cubic meters per hour ( $\text{m}^3/\text{hour}$ ) or 46.92 cubic feet per minute(cfm) at steady state.

### **Fuel consumption rate from methane storage, $y_{2,P2}$**

The second term on the RHS of Equation 4.9 is the other flow variable  $y_{2,P2}$ . This variable is the fuel consumption rate from the methane gas holder storage tanks. The variable,  $y_{2,P2}$ , is the product of the  $k_{2,P2}$  technology coefficient and the fuel cell dispatching pattern  $y_{0,P3}(t)$  which is:

$$y_{2,P2} = k_{2,P2} * y_{0,P3}(t)$$

The flow variable  $y_{2,P2}$  in Figure 4.8 is equivalent to  $y_{2,B2}$  in Figure 4.6. The fuel consumption rate  $y_{2,B2}$  from the methane gas holder storage is equal to the fuel consumption rate of the fuel cell generator  $y_{1,B4}$ . So

$$y_{2,B2}$$

$$= y_{1,B4}$$

$$= k_{1,B4} * y_{0,B4}, \text{ where } y_{0,B4} = \text{the fuel cell output when online}$$

using  $Q$  to represent  $k_{1,B4}$ , we get

$$= Q * y_{0,B4}$$

$$\text{and } y_{2,P2} = Q * y_{0,P3}(t)$$

$$\text{Now } y_{0,P3}(t) = 1.4 \text{ MW} * \text{unitson}(t)\{1 \text{ or } 0\}$$

where  $1.4 \text{ MW} = \text{desired generation capacity}$

$\text{unitson}(t) = \text{on or off based on a dispatch schedule,}$

$$Q = \text{heat rate} * \text{biogas conversion factor from MMBtu to ft}^3$$

$$\text{heat rate} = 7.26 \text{ MMBtu/MWh (Table 3.1, coefficient w).}$$

$$\text{biogas MMBtu to ft}^3 = 1,000,000 \text{ Btu/MMBtu} \div 930 \text{ Btu/ft}^3 \quad (\text{Table 3.1, coefficient x}).$$

So the value of  $Q$  is:

$$Q = 7.26 \text{ MMBtu/MWh} * 1,000,000 \text{ Btu/MMBtu} \div 930 \text{ Btu/ft}^3 = \quad (4.12)$$

Thus for our example where,  $y_{2,P2} = Q * y_{0,P3}(t)$

$$\begin{aligned} y_{2,P2} &= 7.26 \text{ MMBtu/MWh} * 1,000,000 \text{ Btu/MMBtu} \div 930 \text{ Btu/ft}^3 \\ &\quad * 1.4 \text{ MW} * \text{unitson}(t)\{1 \text{ or } 0\} \\ &= 10.17 \text{ MMBtu/h} * 1,000,000 \text{ Btu/MMBtu} \div 930 \text{ Btu/ft}^3 \\ &= 10,929 \text{ ft}^3/\text{hr} \end{aligned}$$

On hours with zero dispatch, the fuel consumption from the tank is expected to be zero cubic feet per hour. On hours with full dispatch level, however the fuel consumption from the tank is expected to be 309.48 m<sup>3</sup>/hr (10,929 ft<sup>3</sup>/hr).

### **Mathematical description of the gas holder storage process, $\psi_2$**

Back on the left hand side (LHS) of Equation 4.9, the rate of change term,  $\frac{d\psi_2}{dt}$  describes the gas holder storage;

$$\frac{d\psi_2}{dt} = P * y_{0,P1} - Q * y_{0,P3}(t) \quad (4.13)$$

$$\frac{d\psi_2}{dt} = D - Q * y_{0,P3} * f(t) \quad (4.14)$$

where  $f(t) = \{\text{on or off}\}$  depending on a schedule of timed events.

$$\frac{d\psi_2}{dt} = D - Q * y_{0,P3} * [1 \text{ or } 0] \quad (4.15)$$

$$\psi_2 = \int D - Q * y_{0,P3} * [1 \text{ or } 0] dt \quad (4.16)$$

$$\psi_2(t) = C + D \cdot t - t \cdot Q \cdot y_{0,P3} \cdot [1 \text{ or } 0] \quad (4.17)$$

When  $t=0$ , Equation 4.17 reduces to  $\psi_2(t) = C$ . Therefore, the constant  $C = \text{initial volume of methane in the gas holder storage } \psi_2(t=0)$ .

$$psi_2(t) = \psi_2(t = 0) + P * y_{0,P1} \cdot t - t \cdot Q * y_{0,P3} * [1 \text{ or } 0] \quad (4.18)$$

$$psi_2(t) = \text{initial level} + \text{refill} * t - \text{fuel consumption}(t) \quad (4.19)$$

where the fuel consumption(t) by the fuel cell = time,  $t * \text{heat rate}, Q * \text{fuel cell generating capacity}, y_{0,P3} * \text{uniton}(t)$

Checking the differentiation of Equation 4.17 with respect to time:

$$\frac{d\psi_2}{dt} = 0 + D \cdot 1 - 1 \cdot Q * y_{0,P3} * [1 \text{ or } 0] \quad (4.20)$$

therefore

$$\frac{d\psi_2}{dt} = D - Q * y_{0,P3} * [1 \text{ or } 0] \quad (4.21)$$

which is the same as Equation 4.15, so good, we have an expression for storage  $\psi_2$ .

### 4.3.1 Other Network Model $k_{i,j}$ Multiliers

The other technology coefficients  $k_{2,P1}$ ,  $k_{1,P2}$ , and  $k_{3,P1}$  for the simplified network in Figure 4.8 must be derived from the extra details in Figures 4.5 and 4.6:

$k_{2,P1}$  from  $y_{2,P1}$  in Figure 4.8 is the technology coefficient for converting raw manure input into digested slurry output by the anaerobic digestion process P1.  $k_{2,P1}$  is equivalent to technology coefficient  $k_{2,A1}$  from  $y_{2,A1}$  in Figure 4.6.  $k_{2,P1}$ , in units (lbs of digested slurry output)/(lbs of raw manure input), is calculated based on the biological volatile solids (BVS) destroyed to create biogas.

$$\begin{aligned} k_{2,P1} &= 1 - (BVS) \text{ destroyed} \\ &= 1 - TS * (VS - RS) / VS \end{aligned}$$

From Table 3.1:

TS (total solids) = 13.3%,

VS (volatile solids) = 11.15%, and

RS (recalcitrant solids) = 8.08%.

So,

$$k_{2,P1} = 1 - 13.3\% * (11.15\% - 8.08\%) / 11.15\% = 0.963380269$$

$k_{1,P2}$  from  $y_{1,P2}$  in Figure 4.8 is the technology coefficient for converting raw manure input into pure methane by Process P1, which is internally the sequential steps anaerobic digestion, biogas scrubbing and purification to pure methane in a pressure swing absorption (PSA).  $k_{1,P2}$  is equivalent to technology coefficient  $k_{1,B2}$  from  $y_{1,B2}$  in Figure 4.6.  $k_{1,P2}$ , in units( ft<sup>3</sup> of pure methane)/day, is calculated based on the purified methane used to refill the gas holder storage.

$$\begin{aligned} k_{1,P2} &= k_{1,B2} \\ &= k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{3,D1}) * (1 - k_{3,D2}) \end{aligned}$$

Using technology coefficients from Table 3.1

$$k_{1,A1} = TS * VS * 5 \text{ ft}^3/\text{lb},$$

$$k_{3,A4} = 0.05\%,$$

$$k_{3,D1} = 42.2\%,$$

$$k_{3,D2} = 31\%,$$

$$\begin{aligned} k_{1,P2} &= k_{1,A1} * (1 - 0.05\%) * (1 - 42.2\%) * (1 - 31\%) \\ &= 0.225217033 \end{aligned}$$

$k_{3,P1}$  from  $y_{3,P1}$  in Figure 4.8 is the technology coefficient for converting raw manure input into a mixture of PSA tailgas and pure methane.  $k_{3,P1}$  is equivalent to technology coefficient  $k_{3,D3}$  from  $y_{3,D3}$  in Figure 4.6.  $k_{3,P1}$ , in units ( $\text{ft}^3$  of mixed tailgas)/day, is calculated based on the tail gas mixture that leaves the PSA and used to run onsite fuel cell cogeneration.

$$k_{3,P1} = k_{3,D3} \text{ from } y_{3,D3}$$

$$y_{3,D3} = y_{1,D3} + y_{2,D3}$$

$$\begin{aligned} k_{3,P1} &= k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{2,D1}) + k_{1,A1} * (1 - k_{3,A4}) * (1 - k_{3,D1}) * (1 - k_{2,D2}) \\ &= k_{1,A1} * (1 - k_{3,A4}) [(1 - k_{2,D1}) + (1 - k_{3,D1}) * (1 - k_{2,D2})] \end{aligned}$$

Using technology coefficients from Table 3.1

$$k_{1,A1} = TS * VS * 5 \text{ ft}^3/\text{lb} :$$

$$k_{3,A4} = 0.05\%,$$

$$k_{2,D1} = 57.8\%,$$

$$k_{3,D1} = 42.2\%,$$

$$k_{2,D2} = 69\%$$



$$\begin{aligned}
k_{3,P1} &= k_{1,A1} * (1 - 0.05\%) * [(1 - 57.8\%) + (1 - 42.2\%) * (1 * 69\%)] \\
&= 0.339750342
\end{aligned}$$

$K_{H2S}$  is the technology coefficient for converting raw manure input into the  $H_2S$  that is removed from the biogas gas scrubbing process.  $K_{H2S}$  is equivalent to technology coefficient  $k_{3,A4}$  from  $y_{3,A4}$  in Figure 4.6.  $K_{H2S}$ , in units (ft<sup>3</sup> of  $H_2S$ )/day, is calculated based on the  $H_2S$  and impurities that are adsorbed onto iron sponge, water traps, particulate filters or other biogas gas sweetening process. Sweetening the biogas produces a fuel that is almost entirely methane and  $CO_2$ . The  $CO_2$  is removed downstream in the PSA.

$K_{H2S}$  from  $y_{3,A4}$

$$= k_{1,A1} * (1 - k_{2,A4})$$

Using technology coefficients from Table 3.1

$$k_{1,A1} = TS * VS * 5 \text{ ft}^3/\text{lb},$$

$$k_{2,A4} = 99.95,$$

$$K_{H2S} = k_{1,A1}(1 - 99.95\%)$$

$$= 0.000282625$$

Note  $K_{H2S}$  is so small that it was removed from the simplified model in Figure 4.8.

Subsequently, it is assumed that  $K_{H2S}=0$ ,  $k_{2,A4}=100\%$  and  $k_{3,A4}=0\%$

### 4.3.2 Requirement for Gas Holder Sizing

Begin by sizing the gas holder bags represented by  $\psi_2$  for 7 days at 8 hours/day that must supply methane,  $y_{2,P2}$ , reliably to the power generator ( $y_{2,P2} = y_{1,P3} =$

$y_{1,B4}$  from Figure 4.6). The power from a 1.4 MW fuel cell x 1 hours = 1.4 MWh.  
Consequently set:

$$y_{0,B4} = 1.4\text{MWh}$$

$$y_{1,B4} = k_{1,B4} * y_{0,B4} \text{ using}$$

$k_{1,B4} = 7.260$  which is the MCFC fuel cell heat rate (technology coefficient from Table 3.1).

$$y_{1,B4} = 1.4 \text{ MWh} * 7.260 \text{MMBtu/MWh} = 10.17 \text{ MMBtu of methane needed per hour.}$$

Therefore  $y_{2,P2} = 10.17 \text{ MMBtu/hour}$

for 4 to 8 hours per day, 5 to 7 days/week and 930 Btu/cubic foot

$$= 218,581 \text{ to } 612,026 \text{ ft}^3 \text{ for the total volume of gas holders}$$

$$= 6,190 \text{ to } 17,331 \text{ m}^3 = 3 \times 2,000 \text{ m}^3 \text{ to } 3 \times 6,000 \text{ m}^3 \text{ gas holders.}$$

## 4.4 Testing the Model

The following is an output of the gasholder storage executable computer model. It was run using the GNU Octave programming language, an open source version of Matlab. The inputs to the program are the number of milking cows that make the manure and the fuel cell size.

---

---

```
octave -3.2.3:95> simplifiedstaticnetwork
```

```
How many milking cows adding manure to digester site? 2000
```

```
How many MW fuel cells for dispatching to the grid? 1.4
```

```
y0_A1 = 300000
```

```

y0_B4 = 1.4000
k1_A1 = 0.56525
K1 = 0.96338
K2 = 0.22532
K3 = 0.33965
y0_P1 = 300000
y0_P3 = 1.4000

```

```

A= [
  1/k1_P1  0      0      0 0 0      0
  0      1/k2_P1  0      0 0 0      0
  0      0      1/k3_P1  0 0 0      0
 -1      0      0      1 0 0      0
  0      0      0      0 1 -1      0
  0      0      0      0 0 -1/k1_P3 0
  0      0      0      0 0 0      1/k2_P3
]

```

```

therefore A=[
4.438127 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000
0.000000 1.038012 0.000000 0.000000 0.000000 0.000000 0.000000
0.000000 0.000000 2.944233 0.000000 0.000000 0.000000 0.000000
-1.000000 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000
0.000000 0.000000 0.000000 0.000000 1.000000 -1.000000 0.000000
0.000000 0.000000 0.000000 0.000000 0.000000 0.137741 0.000000
0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.320328
]

```

Checking to see if A has a determinant.

If no determinant, matrix cannot be inverted.

Determinant of A = 0.59845619

B Vector

300000.00

300000.00

300000.00

0.00

0.00

1.40

1.40

Solutions to the system of equations is:

67596.09

289014.08

101894.13

67596.09

10.16

10.16

4.37

ghsize5x4 = 2.1858e+05

ghsize5x8 = 4.3716e+05

ghsize7x4 = 3.0601e+05

ghsize7x8 = 6.1203e+05

and in Metric

mghsize5x4 = 6189.5

mghsize5x8 = 1.2379e+04

mghsize7x4 = 8665.3

mghsize7x8 = 1.7331e+04

Solution to gas holder size for dispatching power

5 days for 4 hours on the spot market is

218580.65 ft<sup>3</sup> or 6189.51 m<sup>3</sup>

two\_daysrefill = 1.3519e+05

```

five_daysrefill = 3.3798e+05
sevendaysrefill = 4.7317e+05
and in Metric
metric2dr = 3828.2
metric5dr = 9570.5
metric7dr = 1.3399e+04

```

Solution to 7 days of refilling the tank at 46.94 cfm  
with pure methane is:

$$473172.61 \text{ ft}^3 \text{ or } 13398.74 \text{ m}^3$$

Compare 7 days of tank refilling= 13398.74 m<sup>3</sup>,  
with the following MCFC gas holder tank sizes:

$$6189.51 \text{ m}^3, 12379.02 \text{ m}^3, 8665.31 \text{ m}^3 \text{ and } 17330.62 \text{ m}^3$$

Also the onsite generator size, based on tailgas 70.76 cfm is:  
0.18MW

---

---

Looking at the computer output file, because the required storage volume to meet expected power dispatching is equal to 6,190 to 17,331 m<sup>3</sup> and because the refill rate =1,913.23 m<sup>3</sup> CH<sub>4</sub> refill/day = 79.72 m<sup>3</sup>/hour then the following list of inequalities compares the requirement with what is available:

On the left hand side (LHS) is the available quantity of methane in the gas holders for a given number of N days using 79.72 m<sup>3</sup>/hour refill rate\*24\*number of days= minimum gas holder size. On the right hand side (RHS) are the expected consumption by a fuel cell derived from required m<sup>3</sup> storage for D days and 4 or 8 hours per day

.

$3,826.46 \text{ m}^3/2\text{days refill} \leq 6,190 \text{ m}^3 \text{ storage for 5 days, 4h/day}$

$9,566.15 \text{ m}^3/5\text{days refill} \geq 6,190 \text{ m}^3 \text{ storage for 5 days, 4h/day}$

$13,392.60 \text{ m}^3/7\text{days refill} \geq 12,379 \text{ m}^3 \text{ storage for 5days, 8h/day}$

$13,392.60 \text{ m}^3/7\text{days refill} \leq 17,331 \text{ m}^3 \text{ storage for 7 days, 8h/day}$

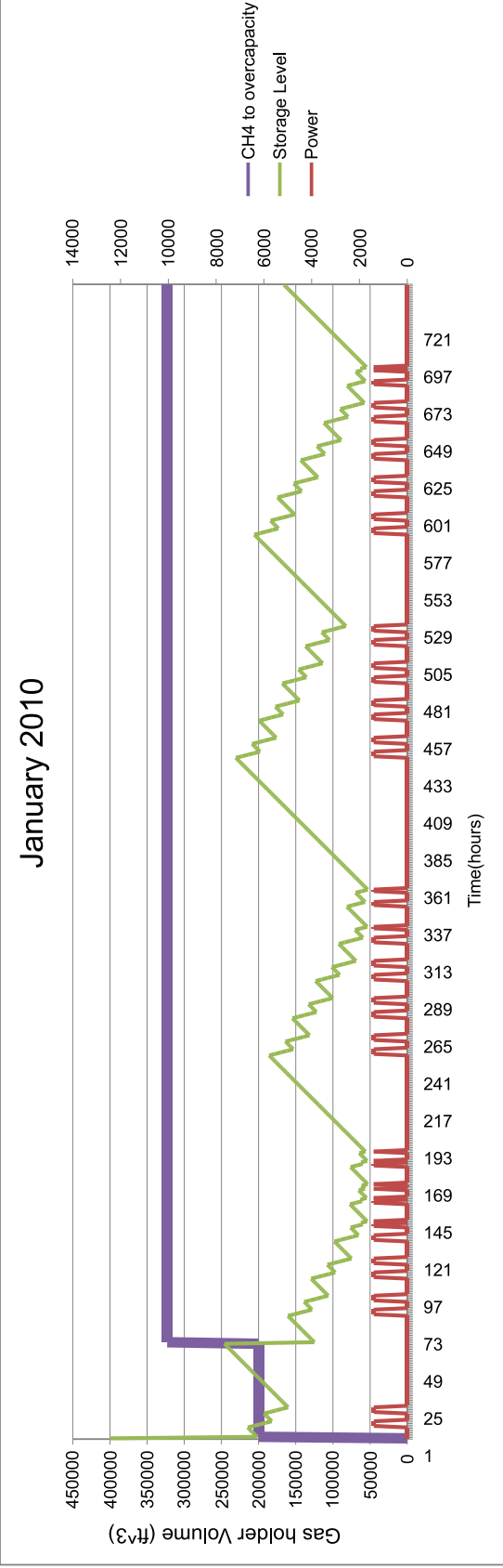
A generic 2,000 milking cow digester site can therefore store pure methane for 7 days and provide all the fuel to generate power on 5 days for 4 to 8hrs/day. This is because  $13,392.60 \text{ m}^3/7 \text{ days}$  available fuel from refill is greater than  $12,379 \text{ m}^3$  storage that is required for dispatch power for 5 days a week for 8 hours per day. Furthermore, 5 days of refills also provides  $9,566.15 \text{ m}^3$ , which is more fuel than the  $6,190 \text{ m}^3$  that is required to generate power for 5 days at 4hrs/day.

The off-peak hours on the weekend (from Friday 11pm to Monday 6am) provides a buffer of 55 hours for refilling of the gas holder as a buffer against spot market dispatching during the week.

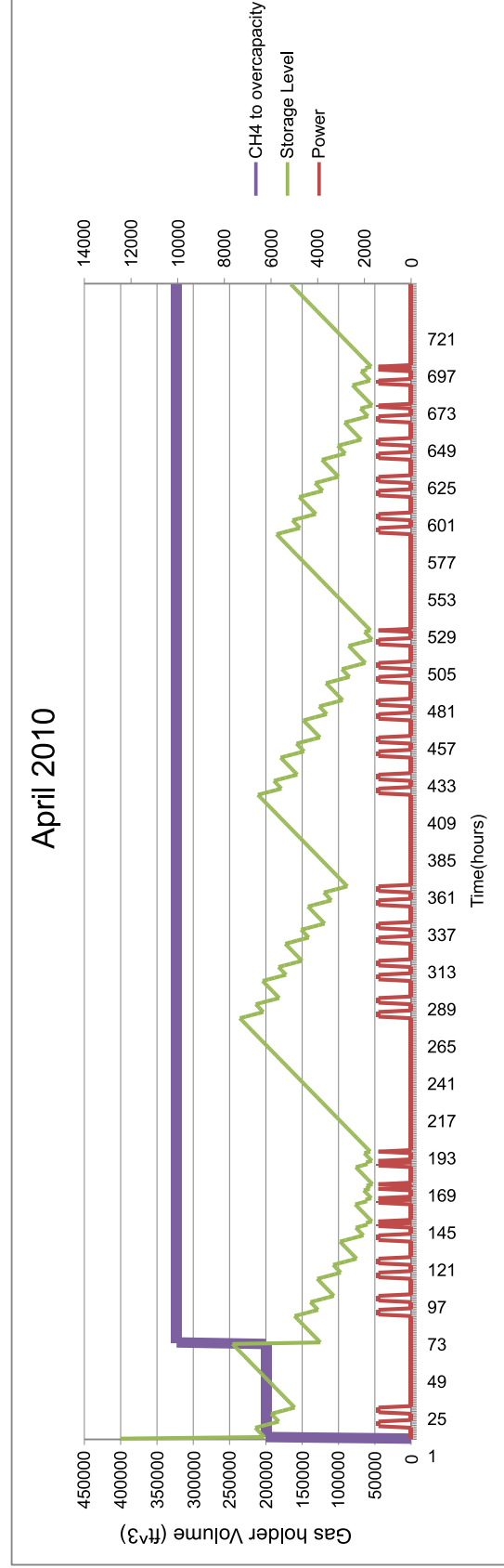
To test the behaviour of month long on/off dispatching cycles, some simple simulations were conducted for January, April, July and October 2010. To accomplish these test required using time series data as historical data from NYISO\* to explore the examples of winter, spring, summer and fall behaviour of the static model (see Figures 4.9 to 4.12 for examples). Also NERC holidays and off peak calendars were downloaded as used to approximate the spot market days when dispatching is possible and the non-spot market days when no dispatching of power is permitted or dispatching is expected to be un-economical.

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\*NYISO 2010, [http://www.nyiso.com/public/markets\\_operations/market\\_data/pricing\\_data/index.jsp](http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp), last accessed Sept 2011)

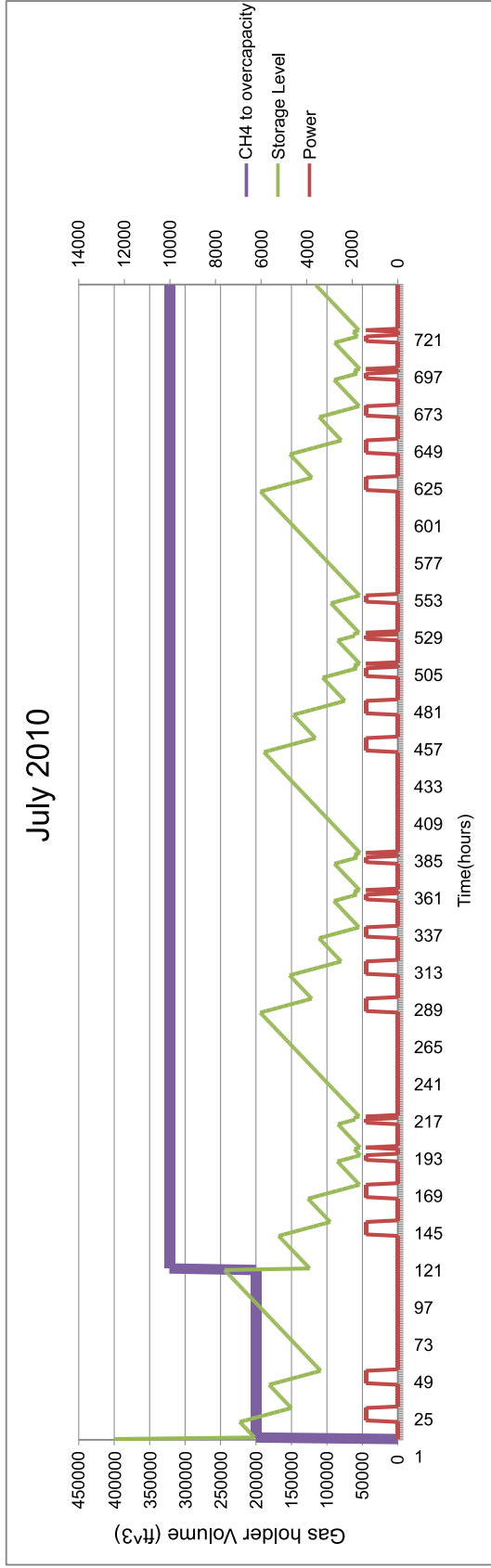


(a) static-cumulative-winter

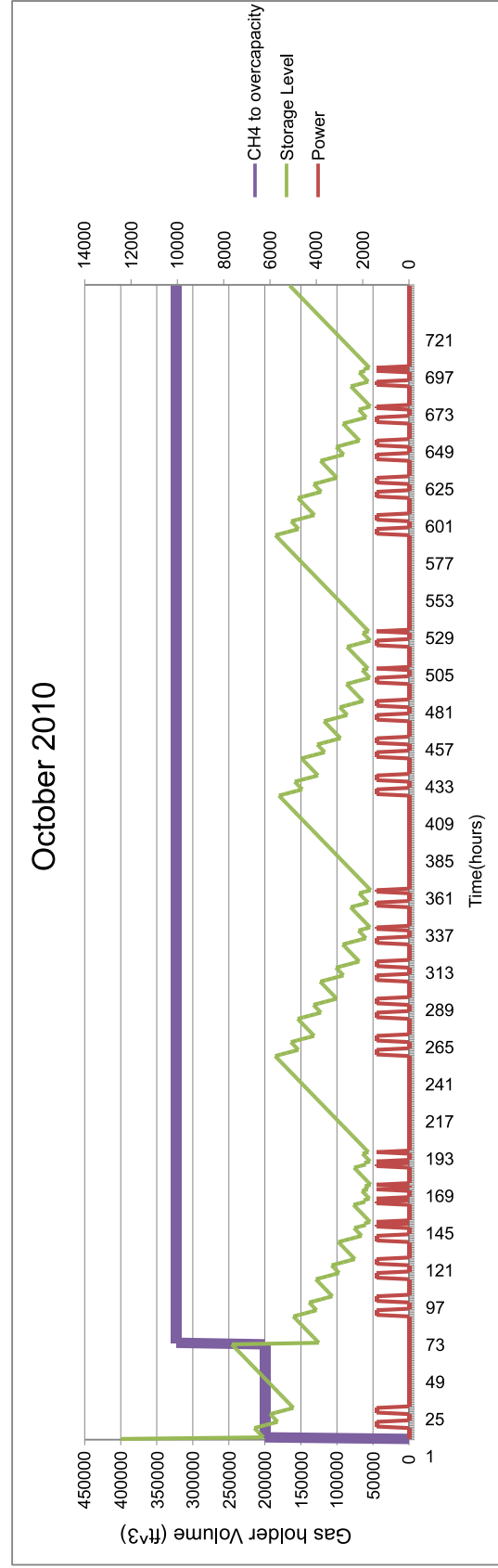


(b) static-cumulative-spring

Figure 4.9: Results of winter and spring 2010 training-sets showing dispatch pattern according to changing gas holder volume and typical twin peaks daily



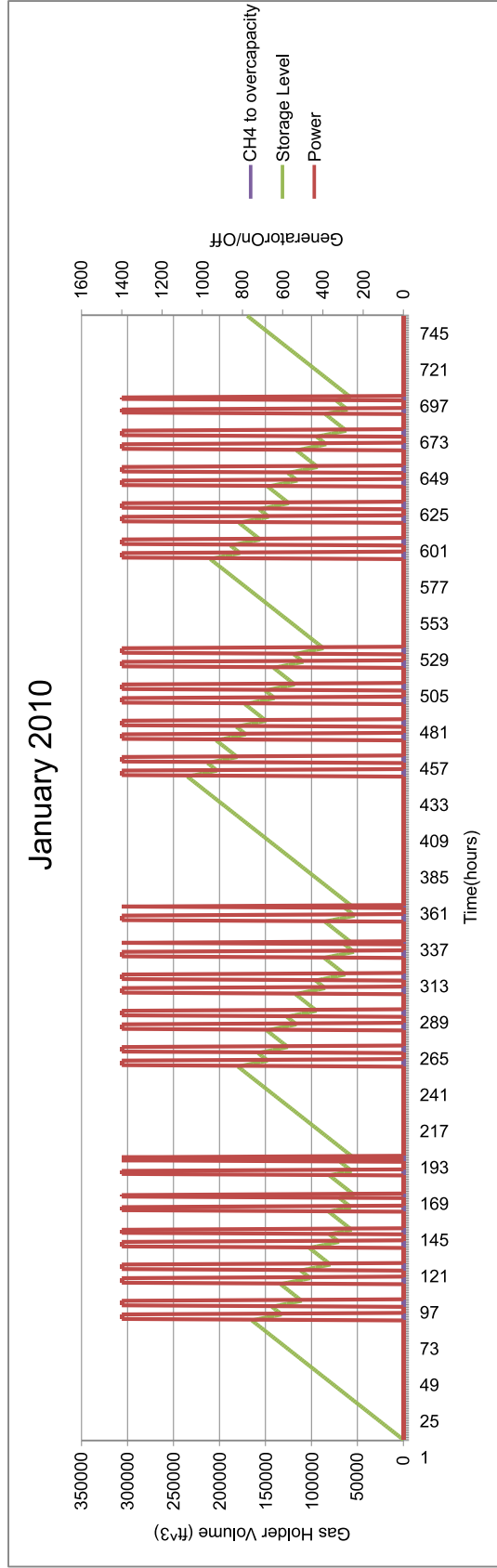
(a) static-cumulative-summer



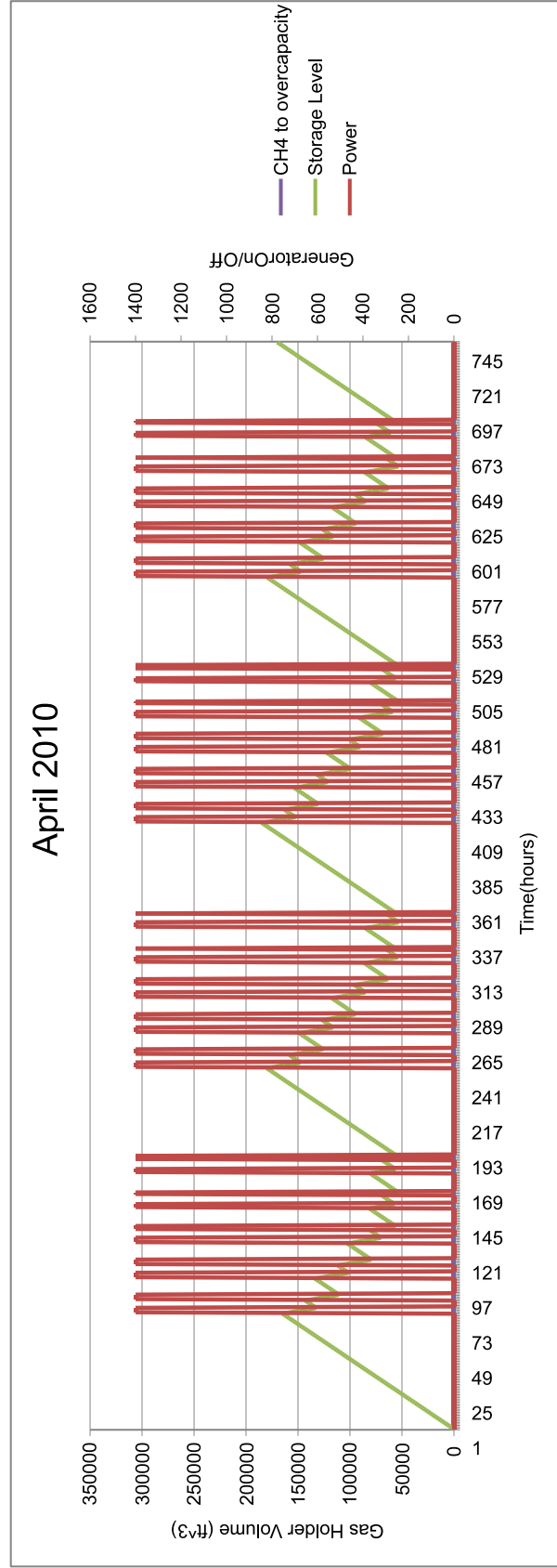
(b) static-cumulative-fall

Figure 4.10: Results of summer and fall 2010 training-sets showing dispatch pattern according to changing gas holder volume and typical one peak and twin peaks daily



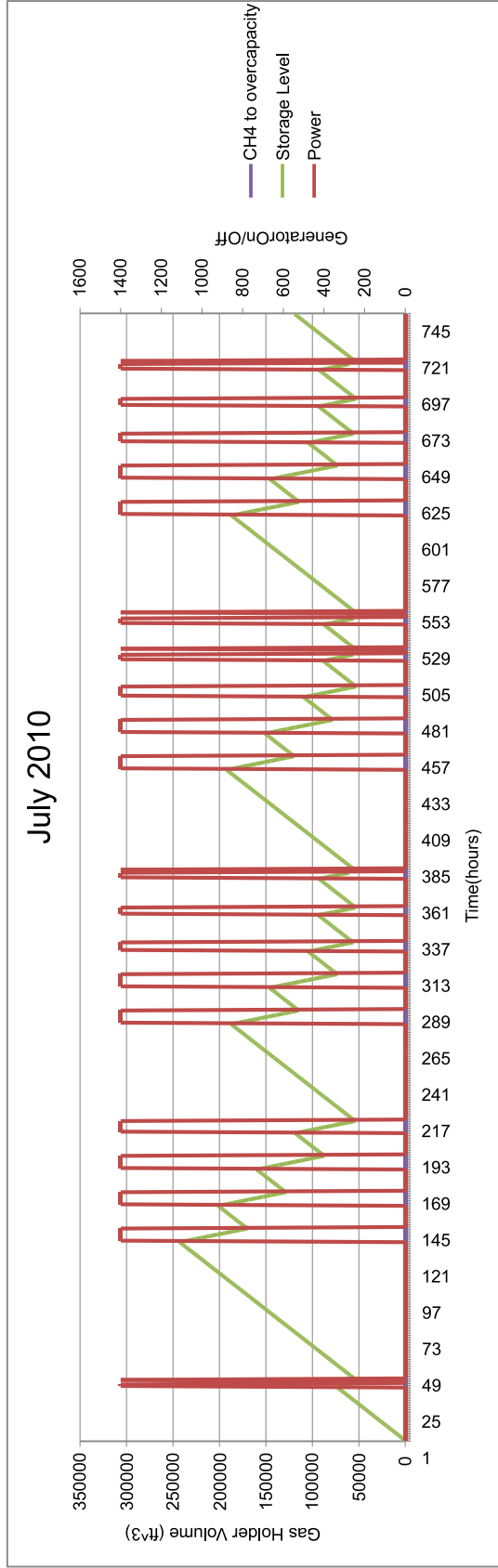


(a) static-cumulative-winter-fromzerovolume

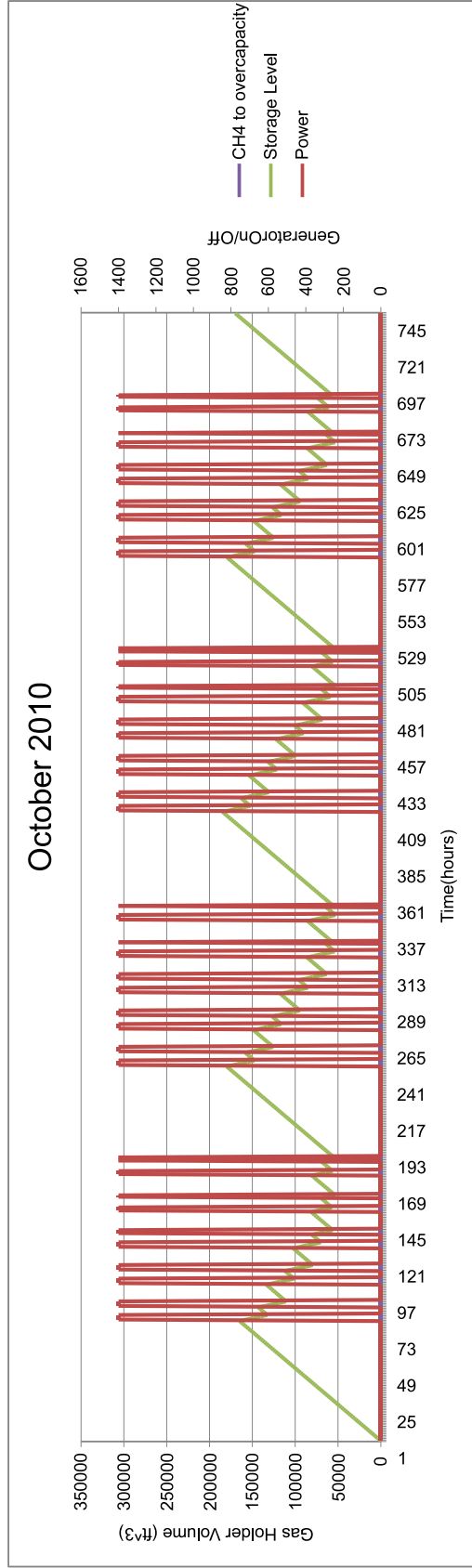


(b) static-cumulative-spring-fromzerovolume

Figure 4.11: Results of winter and spring 2010 training-sets starting from zero volume showing dispatch pattern according to changing gas holder volume and typical twin peaks daily



(a) static-cumulative-summer-fromzerovolume



(b) static-cumulative-fall-fromzerovolume

Figure 4.12: Results of summer and fall 2010 training-sets starting from zero volume showing dispatch pattern according to changing gas holder volume and typical one peak and twin peaks daily

During the 30 to 31 days of operation, the volume of methane in the gas holder was initially set to 400,000 cubic feet or zero. Both kinds of conditions served as a sort of training set to see how the static model for 2,000 cows, 400,000 cubic feet of methane tanks and 1.4 MW fuel cells would be expected to perform. To keep things simple within this chapter, spot market days in the summer months are assumed to have one peak block of 8 hours to dispatch power from 12pm to 8pm as observed in NYISO data.

In alternate simulations for fall, winter and spring months, I assume the characteristic 2 peaks on a spot market day for 2 blocks of 4 hours each to dispatch power. Those two 4 hours blocks of time are 7am to 11am and later 5pm to 9pm (see Figure 4.13 for an example). In the next chapter these generic one peak and two peak patterns are replaced by an algorithm that actually analyzes power load forecasts and day-ahead price signal data to adjust the dispatch pattern to expected peak time demand for power. The last criteria that was added was a minimum level methane in the gas holder just in case of emergencies or onsite needs for the methane that takes priority over selling power to the wholesale market. That value was an arbitrary 1/4 of the full gas holder capacity. For now let us see what the training sets discover from running the simulation with historical data.

Figure 4.13 displays the results of a simple 6 day training set and shows the \$/Mwh price (blue curve) vs. time of day as well as best times to dispatch electricity (red, square wave graph).

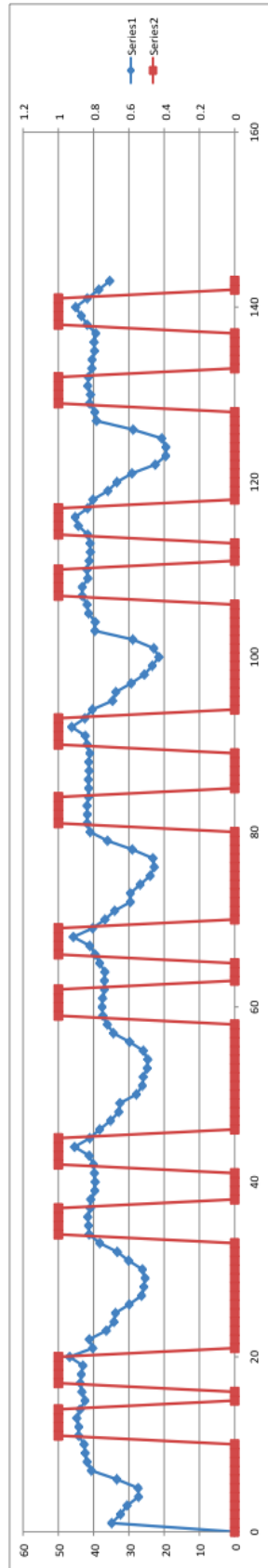


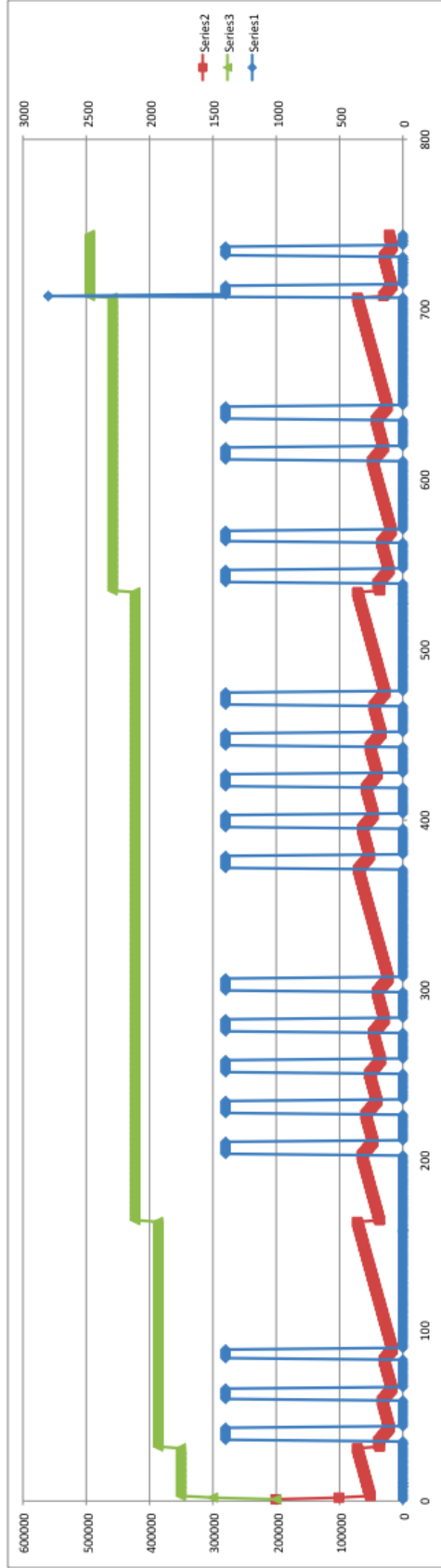
Figure 4.13: Model Training Set

The following are the result from using a training set to see whether the gas holder size and pure methane refill rate works with historical peak load data.

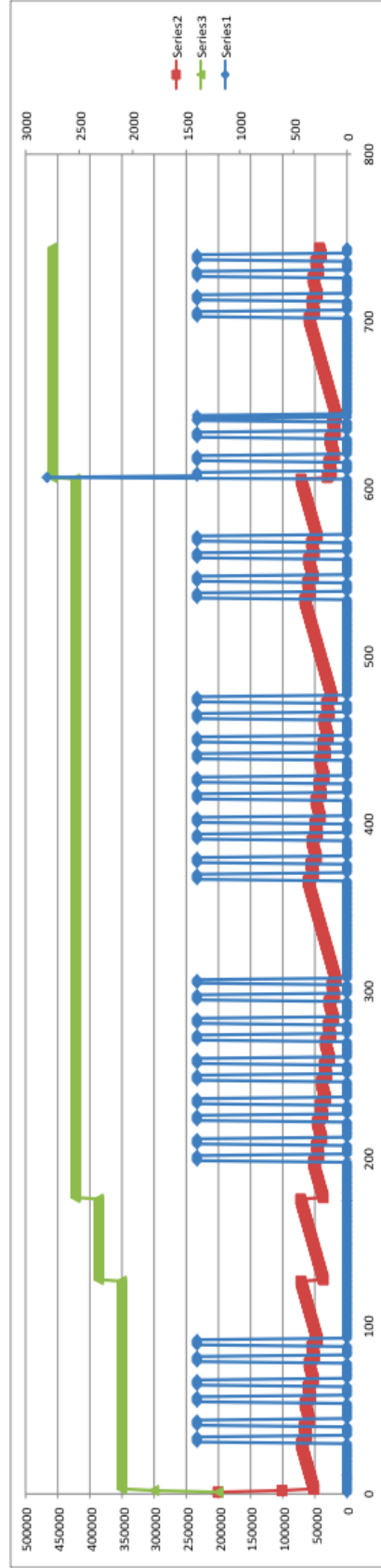
The methane storage level (red), power dispatch status (blue), and cumulative removal of storage overcapacity (green) is shown in Figures 4.14(a) and (b). To get those results it was assumed that only on spot market days that a onpeak dispatch pattern is used to consume  $Q \cdot Y_{0,B4} = 2,083 \text{ ft}^3/\text{hour}$  of methane from the gas holder storage. During those 4 hour blocks the 1.4 MW generators go online to the grid to sell  $1.4 \text{ MW} \cdot 4 \text{ hours} = 5.6 \text{ MWh}$  of wholesale power.

This graph in Figure 4.14(a) is typical of July and the other summer months, where the cogen would dispatch for the 8 hours in the center of peak time, sometimes called super peak, from 11am to 7pm.

This next graph in Figure 4.14(b) is for the winter onpeak pattern, dispatching during the morning peak periods of 7am-11am and evening peak time 5pm to 9pm.



(a) static-cumulative-summer



(b) static-cumulative-winter

Figure 4.14: Results of summer-and-winter-training-set showing one peak and twin peaks respectively

## 4.5 Next Steps

The 2,000 cows starting point for this simulation was somewhat arbitrary. My previous work with AA Dairy farm's 500 cow farm resulted in a recommendation for a 250 kW fuel cell system. To meet the NYISO 1 MW system I proportionally scaled up the number of cows from 500 to 2,000 cows by a multiple of 4 to get around  $4 \times 250 \text{ kW} = 1 \text{ MW}$ .

In the next chapter, forward looking simulations switch our efforts from what we just covered (training and sizing the system) to actually dispatching power from the system (based on market forecasts and power price signals.)

## CHAPTER 5

### **DYNAMIC MODEL: ON-PEAK FUEL CELL DISPATCH USING SPOT MARKET PRICES AND STORED DIGESTER METHANE**

From the point of view of a independent power producer (IPP) or industrial plant, purified pipeline quality biogas called renewable natural gas (RNG) and the commodity fossil fuel called natural gas (NG) are virtually indistinguishable. They both contain 95-99% methane and both forms of pipeline natural gas are the cleanest burning (low soot production) widely available fuels for onpeak gas turbines and combined cycle gas turbines. According to 2009 data New York State gets 31.4% of its total electricity generation from NG, second only to nuclear power which is 32%.<sup>25</sup> Among IPPs in 2009, natural gas fired generation is about the same percentage 30.4%.<sup>25</sup> It is important for IPPs that operate with digester derived biogas to consider participating in the natural gas spot market.

In this chapter I will talk about RNG and NG interchangeably. The purpose of this chapter is to develop and test a dynamic computer model for selling power to the spot market from an IPP. The desired power dispatch is intended to respond to price signals and the changing dynamics of the NG pipeline and wholesale power grid. The IPPs make the decision whether to dispatch or withhold power.

#### **5.1 Introduction**

In an uncertain world with escalating energy prices, increasing demand for electrical power, electrical grid congestion, loss of electrical power and brownouts, Hsu stated that dispatchers that operate the IPPs look at peak load generator assets like a series of spark spread call options.<sup>39</sup> That is, IPPs view onpeak generator assets from a risk management perspective - as a series of revenue streams and costs. Especially at natural gas fired plants, power dispatch operators at the IPP



set out to maximize the chance of earning a steady or increasing revenue, while minimizing the risk of relatively high natural gas costs that do not result in higher electricity revenue to run their distributed generation business. Net metering is not risk management.

The simplest risk management method for an IPP or generator plant company (Genco) is: to dispatch power only when the electricity selling price is greater than the cost of generating electricity from a natural gas genset and make provisions for positive revenue even when the generator is shut down. Because the Genco has the right to turn on or off depending on price signals and other conditions on the market, Gardner<sup>78</sup> and Hsu<sup>39</sup> state that this is the same behaviour of a stock option. Consequently, natural gas power plant owners view their assets as a series of spark spread options.

Instead of continuous electricity generation of biogas power from the digester site and dispatching according to net metering, this chapter describes an alternative dynamic computer model for spot market dispatching of electricity generated from stored biogas and fuel cell CHP stacks that are grid interconnected to sell wholesale power. The first section provides a brief introduction to wholesale power, spark spreads and payout functions before proceeding to the system framework and research approach that I developed in this chapter to shift the business from power net metering to dynamic power trading on the electrical power spot market.

## **5.2 Retail, Wholesale and Spot Market Prices**

The spot market is a publicly traded market just like the stock market and commodities market. Investors use public markets as a common clearing house to buy and sell commodities and securities including shares, options, futures, mutual funds, bonds and contracts. In this study, the spot market refers to the spot price

based energy commodity marketplace.<sup>79</sup> The commodities are mainly wholesale electricity and pipeline natural gas. Spot markets are very different from futures markets because commodities and money are delivered immediately as opposed to delivered at a later date. In fact, electricity bought and sold on the spot market is delivered as close to the time the energy was produced as possible and consumed immediately.<sup>80</sup> The time frame for the electricity spot prices in New York are actually day-ahead, hour-ahead or real time.<sup>81</sup>

Natural gas spot prices for New York is assumed to be the NYMEX (New York Mercantile Exchange) prompt month futures contracts.<sup>82</sup> Likewise, the electricity spot market for New York is assumed to be the NYISO/FERC Day-Ahead location based marginal price (LBMP) market. It would be advantageous and very rewarding for digester sites to capture a piece of the day ahead market earnings in the following graph (Figure 5.1). For year 2009, the NYISO estimates \$11 billion annually in wholesale electricity traded, and 51 percent of that, was \$5.6 billion in day ahead.<sup>83</sup> NYISO estimates 39,629 MW installed capacity in 2009 was from 500 generators.<sup>83</sup>

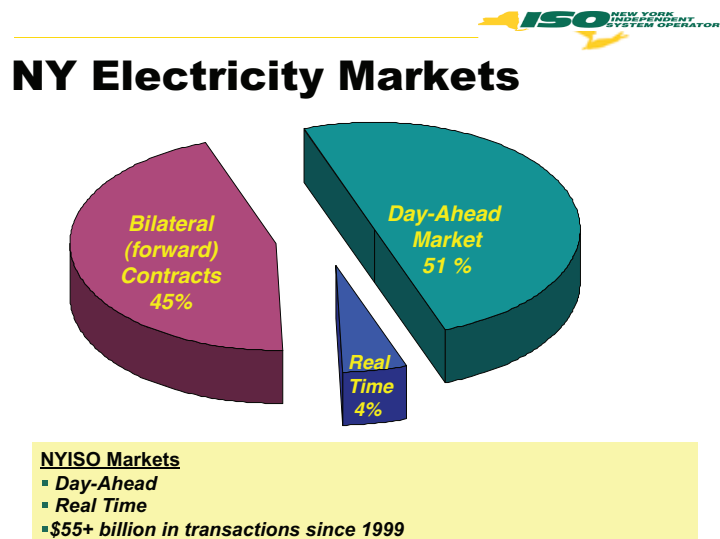


Figure 5.1: NY electricity market in 2009. [Source: Nelson,2009]

Consumers in retail electricity markets rarely get the opportunity to buy or sell electrical power at spot prices.<sup>84</sup> The retail market customers do not get that chance because electricity spot prices are only designated as wholesale electricity prices. Wholesale power prices are the prices paid for Megawatts (MW) of power transferred on the transmission grid and these prices vary widely during the course of the day from low and even negative values to extremely high prices. Consumers and small distributed generators interconnect to the grid by way of the distribution grid at the delivery level compared to the transmission grid level used by centralized power plants of public utilities and big industrial plants as shown in Figure 5.2. In that figure consumers interconnect at levels 5 and 6 and centralized power plants interconnect at levels 1, 2 or 3.

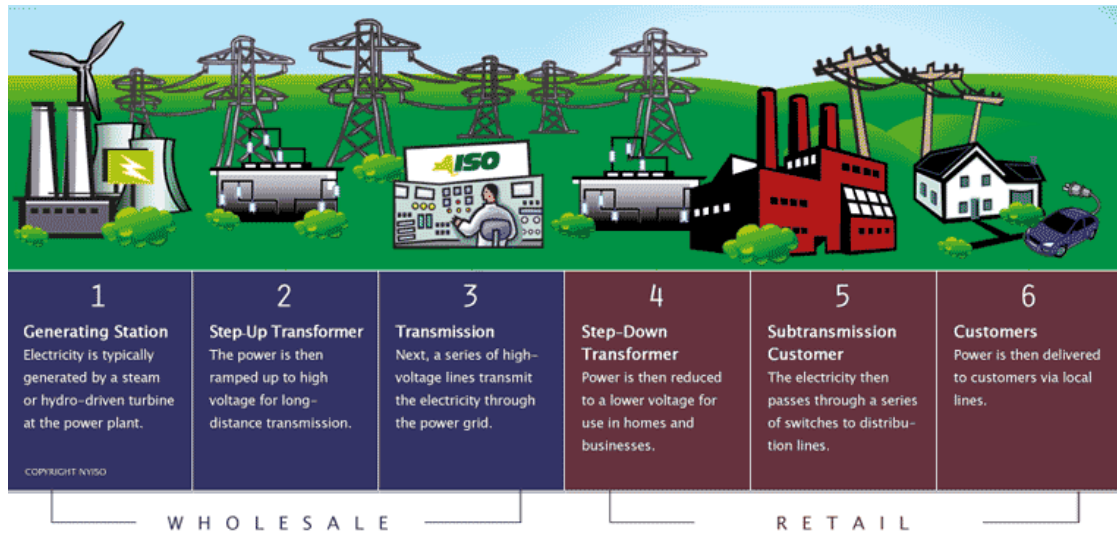


Figure 5.2: Present day grid in New York showing the wholesale and retail segments of the market. (Source: NYISO)

Electricity and natural gas are physical commodities that are traded in the spot markets using wholesale prices as opposed to retail prices. Retail prices are the flat rate \$/kWh prices and fixed time-of-use \$/kWh prices that small to medium consumers pay according to a electricity rate structure of the power delivery companies. Those delivery utility companies have been allowed by the New York State

Public Service Commission (NYSPSC) to collect revenue from different designated rate classes (ranging from home owners, small farms, commercial buildings, to big industrial complexes) of electricity customers to run their grid infrastructure and services for a guaranteed profit.

Time of use reflects the cyclical demands of energy users during a 24 hour period. The grid is most strained during the daylight and waking hours of the day from 6:00 to 22:00. Consequently the on-peak prices for buying power from generators is higher than off-peak times. Within the onpeak period are different categories: mid peak, super peak and shoulder peak times. As one might expect, it is more profitable to react only to high electricity prices by generating during those limited lucrative onpeak time blocks versus only collecting avoided cost prices for power paid by the local utility all the time (onpeak and off peak). The following sections of this chapter develop the case for how to dynamically maximize profitable power sales at a digester site.

Figure 5.3 shows an example of the actual power demand (MW) curve in the Central Zone C from the New York Independent Service Operator (NYISO) (the top line which is darker) along with the real time (RT) location based marginal prices (LBMP, in \$/MWh) (the bottom line which is blue/grey.) One can interpret the flatter areas of the bottom RT LBMP graph to be on average \$20/MWh to meet the load; therefore, selling 2 MWh of power for 1 hour would result in a \$40 payment. At 12 pm, on that RT LBMP graph for the date 5/12/2010 with a LBMP of \$325/MWh, selling 2 MWh for 1 hour would result in \$650 payment which is much better for an IPP than the \$40 we just mentioned.

To meet those limited time blocks of higher paying electrical loads, Gencos bid day-ahead market (DAM) power capacity commitments (the bottom graph of Figure 5.4) to the NYISO by 5am the day before. By 11am on that day of the bid

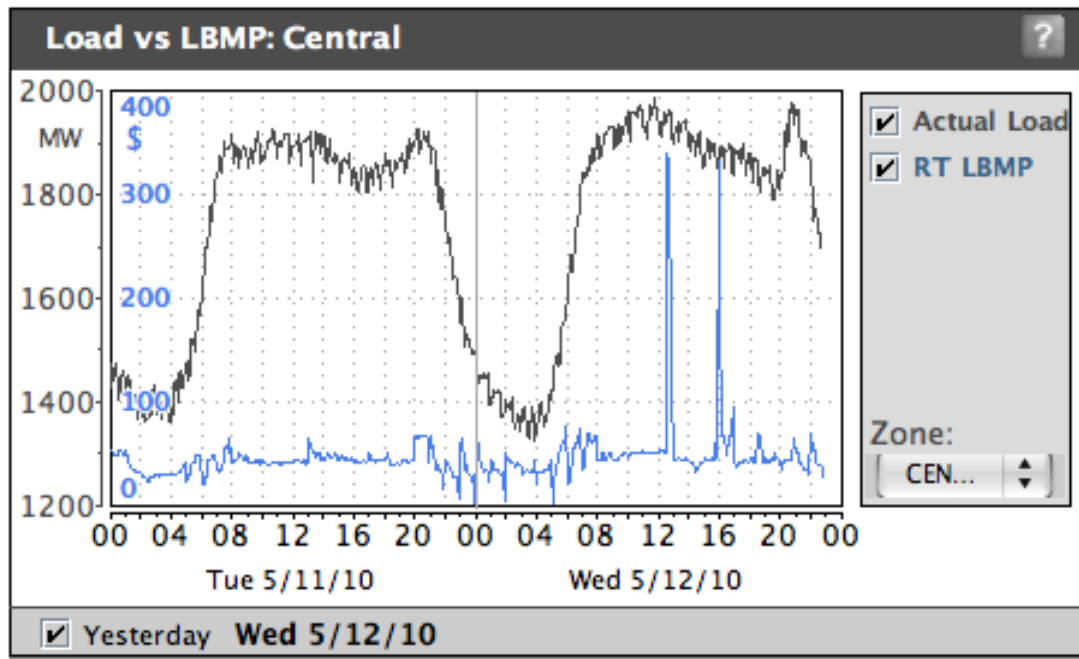


Figure 5.3: Wholesale Power Demand (MW) and LBMP (\$/MWh) curves in the central zone C from the NYISO

the least cost generators are selected by NYISO. It is observed that actual MW capacity load (top gittery graph in Figure 5.4) exceeded the forecasted MW of power demand (middle graph in Figure 5.4) on both sample days indicating that the higher prices had to be used to incentivize all power producers to sell more than previously expected the day before. Those economic incentives can also be used to trigger biogas dispatchers to generate instead of stay offline. Notice that the DAM commitments from IPP and other power plants (bottom graph in Figure 5.4) make up only a fraction of the total power generated to satisfy the NYISO load. The centralized power plants and out of state ISO's provide the remaining fraction of the generation.

Like heavily capitalized hydro power plants, nuclear power plant units and combined cycle natural gas peaking units, the biogas dispatching plants' operators cannot afford to be offline all day. Biogas plants could, however, be dispatched at

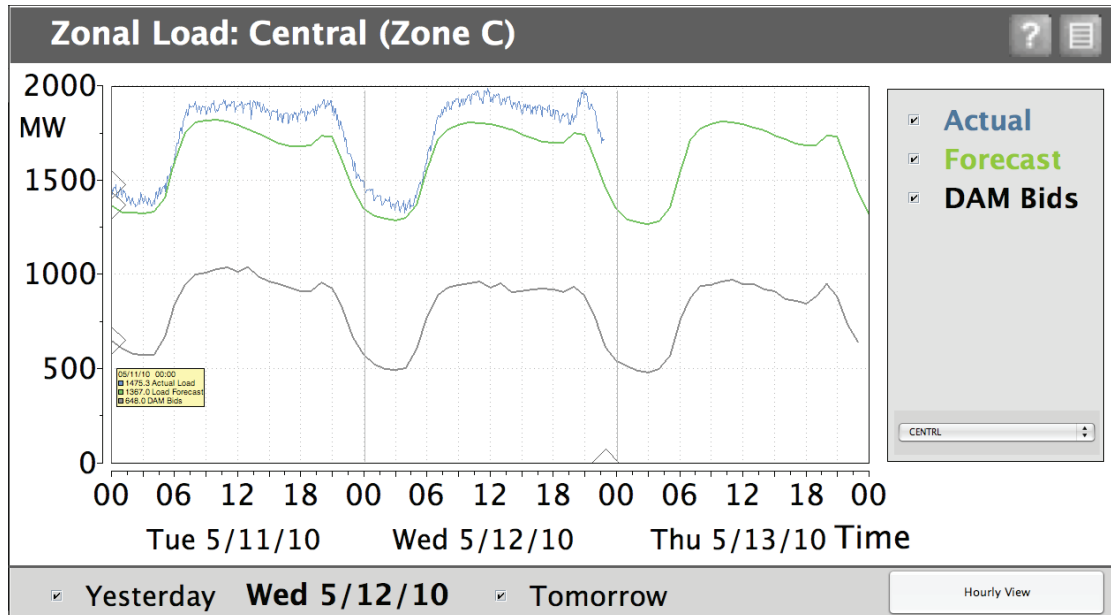


Figure 5.4: Actual Load, Forecast and Day Ahead Bids for Central Zone C on May 12, 2010 from the New York Independent Service Operator (NYISO)

a high generation capacity level part of the day and be switched to low generation level or offline the rest of the day according a dispatch schedule. The biogas plant would assess the forecast for grid load demand to pick the anticipated highest peak times and bid the plants capacity during those high onpeak times at a cost of \$0/MWh just like hydro power plants and nuclear power stations in Figure 5.5.<sup>85</sup> That guarantees that they will always be selected as a lowest cost generator when the NYISO stacks up the offered bids to determine the entire NY system's marginal price for each of the 11 NYISO zones (A through K) in the state.

Similar to natural gas peaking units, a biogas Genco dispatcher would operate the fuel cell or generator under constraints such that they restrict grid sales to only onpeak times of the spot market days and set a minimum \$/kWh or \$/MWh price to react to and generate power by its cogenerators ramping up to come online. Meeting the optimal solutions for these constraints, the biomethane power dispatch site would then proceed to sell generated power in order to cover its marginal costs

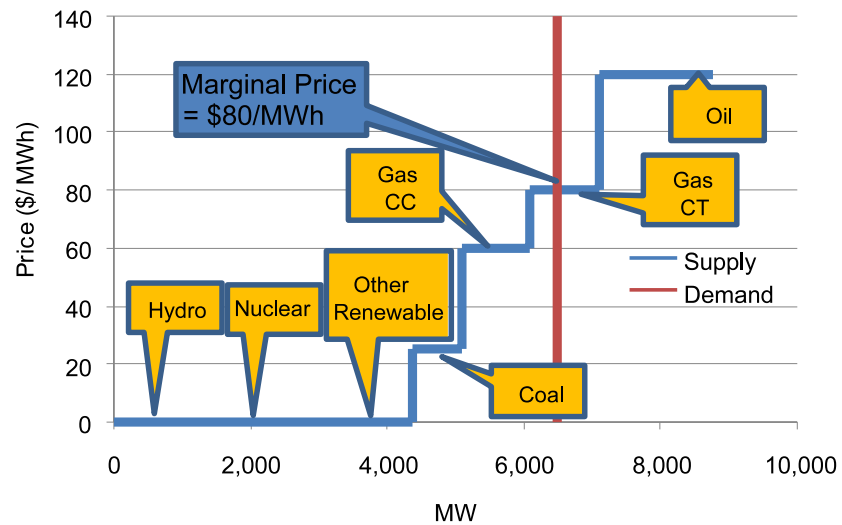


Figure 5.5: Setting the location based marginal price (LBMP) by stacking offered generator bids and selecting the highest offer price that clears the NY system demand (adapted from [Source: Stern, 2009])

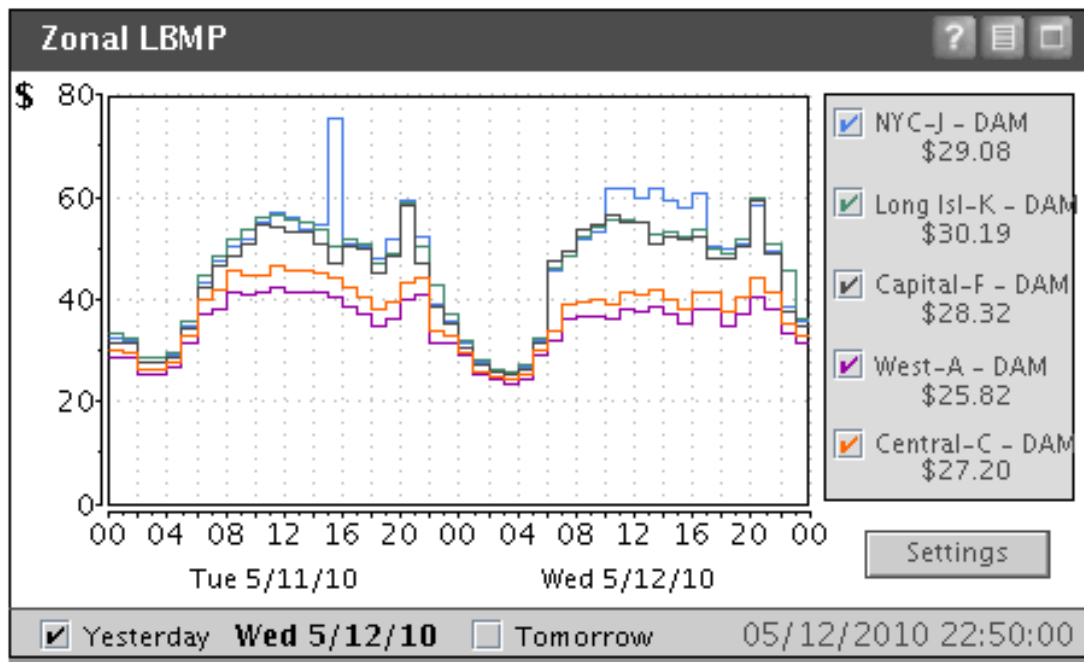


Figure 5.6: Day-Ahead LBMP for central zone C and 4 other zones on May 12, 2010 from the New York Independent Service operator (NYISO)

(operating and fuel costs.) Profit for the biomethane dispatch site results when the electricity revenue exceeds the NG fuel cost and the fixed and other costs. Under proper market conditions the generator owner would only sell to the wholesale market when the spot market electricity price is high enough to exceed costs. Figure 5.6 has five example curves for two days in May 2010, containing Day-Ahead Market LBMP prices for five NYISO power zones including the central zone C which is for Central New York where some of the Dairy CAFOs used in later case studies are located. Those DAM LBMP in Figure 5.6 are the least \$/Mwh settlement prices NYISO will pay to the generators whose bids prices were accepted for each hour over that 48 hour period in May 11 and May 12.

Then the generators could have the option of adjusting the day-ahead scheduling plan to fine tune the dispatch decision to respond using hour-ahead (15 minute intervals) and Real time (5-minute interval) data in order to get the best revenue outcome. Figure 5.7 shows how complex and volatile the LBMPs do get when considering whether to use DAM LBMP prices [flatter blue graph], HAM LBMP prices [red graph] or RT LBMP prices [green graph] as a basis for real time scheduling. We stick with using the step shaped day-ahead LBMP prices in our modeling.

What's the best way to dispatch power using many data streams from NYISO? May we use linear programming to find the best choice? Or, is there another contractual based approach to get higher payments for biogas generation? I prefer mixing the two methods.

Natural gas (NG) peaking power marketers do not use only electricity prices as a guide for deciding when to sell and not to sell. Instead the transaction about what time block to sell NG-derived electricity is based on the spark spread which is defined in Equation 5.1 as the difference between the the spot electricity price and the product of the heat rate multiplied by the spot natural gas price:



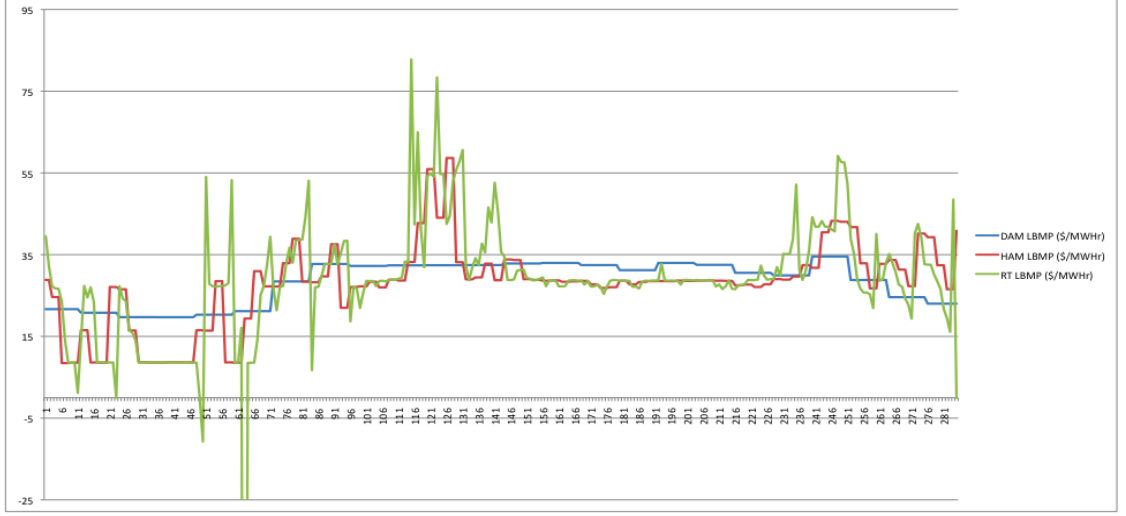


Figure 5.7: Day Ahead (DAM), Hour ahead (HAM) and Real Time (RT) LBMP on May 12, 2010 from the New York Independent Service operator (NYISO)

$$\text{spark spread } (SS) = (P_{elec} - HR * P_{ngas}) \quad (5.1)$$

$$\text{payout function } \pi_{or} F(P_{Elec}, P_{NG}) = \max[(P_{Elec} - OHR * P_{NG}), 0] \quad (5.2)$$

where:

$P_{Elec}$  = spot market electricity price

OHR = operating heat rate

$P_{NG}$  = spot market Price for electricity

According to the literature<sup>39,78</sup> when a generator owner has the right but not the obligation to sell electrical power based on spot market conditions, this decision is the same as a stock market exchange call option. Figure 5.8 is a payout diagram from Hsu 2001<sup>39</sup> for a natural gas generator with a heat rate of 7 MMBtu/MWh, spot market price for electricity \$0 to \$50/MWh and natural gas spot price of \$0 to \$10/MMBtu.

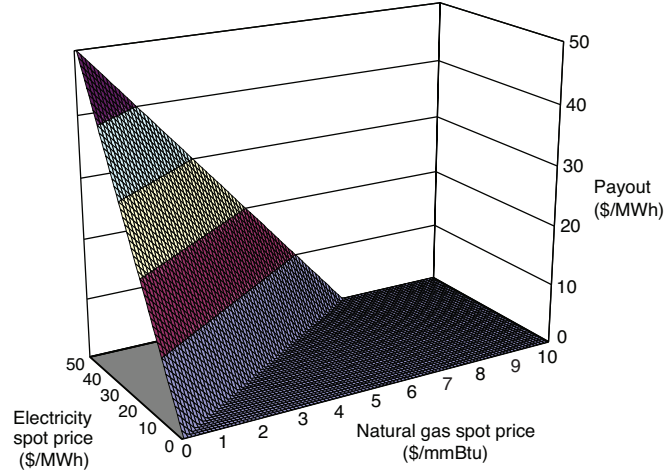


Figure 5.8: Simple payout function(Source Hsu, 2001)

Using the notation  $F(P_{Elec}, P_{NG})$  for the payout value in Figure 5.8 corresponding to spot market electricity and natural gas prices  $P_{Elec}$  and  $P_{NG}$ ; then the graph shows:

$$F(50, 0) = \$50/\text{MWh}$$

$$F(35, 4.25) = \$0/\text{MWh}$$

$$F(0, 0) = \$0/\text{MWh}$$

Which combination of three variables can be used to extract more than 50% of the maximum theoretical spot market price more than net metering? That is the original thesis question.

The spot market natural gas price  $P_{NG}$  would have an effect on the operating cost and profitability of a biogas generator at the digester site. This was first stated to me by Seneca Foods Corporation \* That being said, the cost of purifying biogas to just scrubbed biogas ( $\text{CH}_4$  and  $\text{CO}_2$ ) or pipeline quality methane ( $\text{CH}_4$  with  $\text{CO}_2$  removed) affects the operating cost and profitability of a biogas electricity

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\*Personal Communication with Seneca Foods Montgomery Plant Manager, Paul Hendrickson when explaining that biogas is competing with the commodity natural gas that SFC trades every day in their commodities and risk management division for all of the company's food processing plants worldwide.

generation at the digester site.

Many food processing factories and commercial commercial and residential clients already have natural gas pipelines bringing a predetermined or on-demand quantity of a fuel (measured in Therms or MMBtu) to the site. Alternatively trucks drive in the quantity of fuel (measured in MMBtus) to the site as propane and fuel oil. When a quantity of a delivered fuel is purchased ahead of time as a commodity good under fixed price contracts the “prompt month” price is fixed for every day during that month. The price of fuel for generation affects the profitability and operating costs of the generator.

The spot market electricity price  $P_{Elec}$  also affects the operating cost and profitability of a biogas generator at the digester site. When neither the electricity price nor the natural gas price are fixed but variable depending on the market calls, the generation owner should calculate the spark spread.

This revenue payout function in Equation 5.2 and shown above in the Figure 5.8, ensures that the owner generates positive money or zero and does not possibly have room for negative money. A power dispatcher who uses stored biomethane should shut down the grid-connected generator in anticipation of and during negative spark spreads.

Having a fixed-price everyday per month for natural gas or purified methane from digester biogas reduces one level of risk and cost forecasting. Take the example of a combined cycle gas turbine (CCGT) in Hsu, 2001,<sup>39</sup> which has a heat rate of 7,000 MMBTU/kWh, then Figure 5.8 is the corresponding diagram of the expected payout function. When the natural gas price is fixed at a constant \$4/MMBtu for the whole month then the graph simplifies to Figure 5.9.

The interpretation of Figure 5.9 is that below a spot market price of \$25/MWh the generation system should stay OFFLINE. Above spot market prices in excess

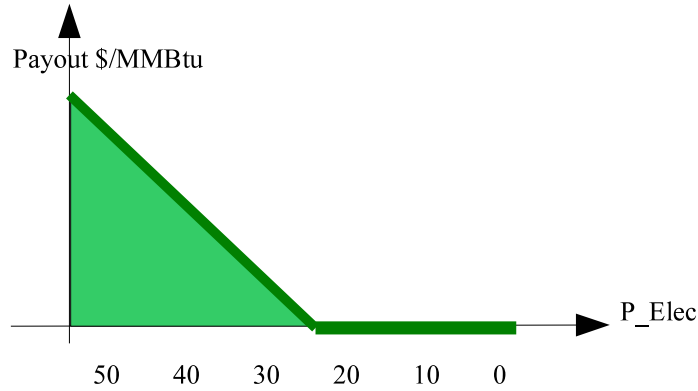


Figure 5.9: Slice of the 3-D payout graph when  $P_{NG}$  price is \$4/MMBtu

of the \$25/MWh strike price, the generator must stay ONLINE and collect higher profit.

While going online and offline is the desired decision based on exceeding a threshold of spot market prices, it does not by itself ensure a steady income stream. Consequently this is a risk management problem. Recall Hsu said that owning peaker natural gas generator assets is like owning a series of spark spread call and put options — that need to be managed properly<sup>39</sup> to generate revenue. To get steady income one needs to do a tradeoff between real time dispatching and change the topology of Figure 5.8 to the topology of Figure 5.10 by locking in a guaranteed profit margin. That profit margin is derived from buying fixed price electricity contracts (the day before) and fixed price natural gas contracts (the month before) from the commodity futures market. In investment speak, we have call put parity and traded part of the high profit making potential that exists during times of positive spark spreads instead for a guaranteed profit margin. The result is a minimum guaranteed profit instead of chance for zero revenue. This is a more sophisticated form of risk management than net metering. Tolling agreements are based on this put call parity method.

In order to make debt obligations and other payments year round, Hsu<sup>82</sup> sug-

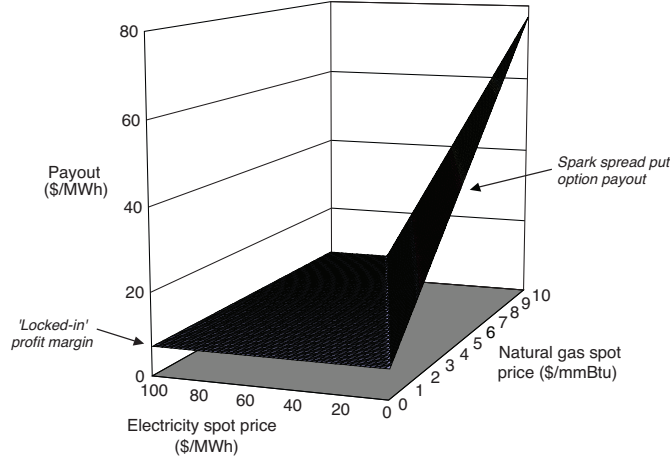


Figure 5.10: Locked in profit Margin (Source: Hsu, 2001).

gested using hedging techniques to help with risk management of the generating assets. From the perspective of risk management, many dispatch operators at a Genco view generating assets, such as fuel cells and gas turbines, as a series of spark spread call options and spark spread put options. As discussed previously, spark spreads calculations for our particular dispatch system problem involve the using fuel cell's operating heat rate, spot electricity price and spot natural gas price as variables in the payout function. We can effectively hedge against times with negative spark spreads by using a method to lock in a guaranteed profit margin and buying options.

### 5.3 System Description

Figure 5.11 illustrates the boundaries of the dynamic computer system that we will define for power generation and dispatching from anaerobic digesters and  $\text{CH}_4$  gas holder storage. It is based on a simplified version of Figure 1.1. As can be seen, there are two subsystems, referred to as SBA and SBB, which have inputs and outflows as well as, processes and interconnections between them.

To be eligible for the NYISO's Demand Sided Ancillary Service Program (DSASP)

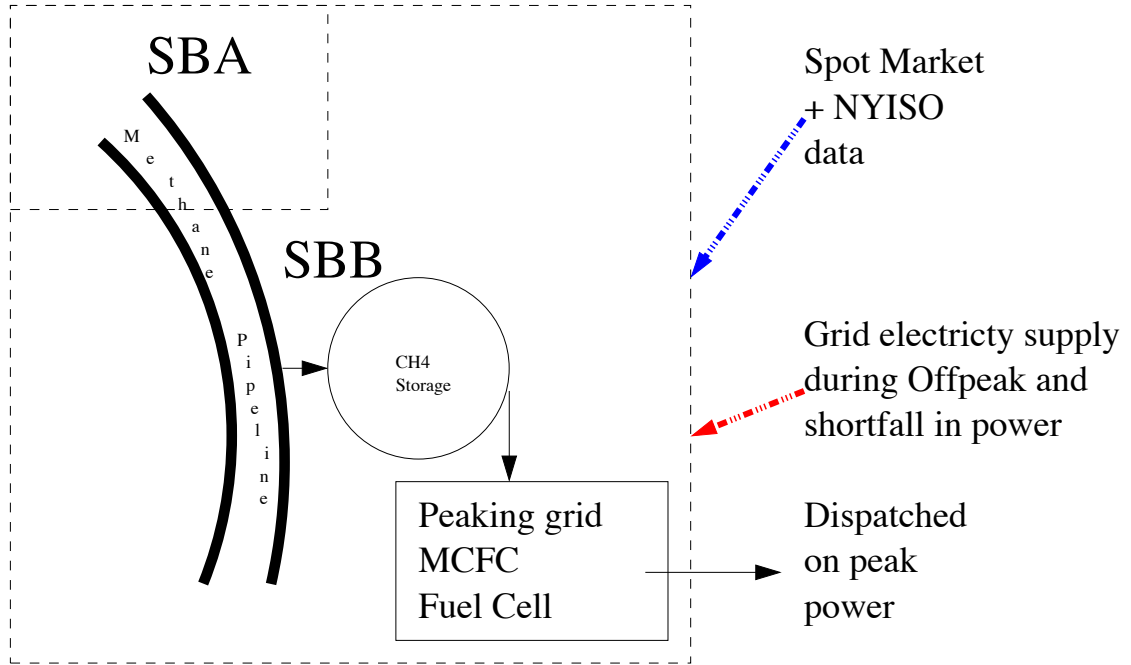


Figure 5.11: Defining system boundaries for the dynamic model

and the NYSPSC standard interconnection requirements (SIR)<sup>40</sup> a generator owner must have minimum 2 MW grid generation capacity behind the fence. This requirement is only 1 MW for 4 hour blocks of time from power systems selling electricity directly from digester sites.<sup>40</sup> At this time, there no clear indication if a distant site with 99% pure methane in gas holders counts for 1MW or 2MW. Analysis in the previous chapter, Chapter 3, showed that the generation and storage of methane that is required to deliver this capacity over five weekdays for one 4-hour block/day is around 140 MMBtu of pure methane in gas holders. The gas storage capacity would doubled for two 4-hour blocks per day. Use of this kind of analysis showed that such gas storage capacities are unlikely to be achieved on a single farm [with less than 2,000 cows], especially for the kind of MW electricity generating capacity required for 8 hours per day production. Thus, the physical scale of the modelled dynamic computer system is a large network: one 1MW scale generator owner at SBB having gas holder fuel storage (measured in units of MMBTu) , and one or

many digester owners at SBA who supply the pipeline methane (in MMBtu) to the gas holder tanks at SBB. The cogeneration modules are molten carbonate fuel cells (MCFC) that produce combined heat and power (CHP) from the methane fuel. Three kinds of energy flows are presented in the system: methane flow (in scfm), electrical energy (in MWh) and embodied energy flow (in MMBtu). It is assumed that all pipes, thermal storage tanks, and methane storage tanks are well insulated but in reality some waste heat is assumed to occur. Internal needs for power are supposed to be negligible or provided by another source of fuel, not the pure methane in the gas holder but most likely the mixed tail gas stream that was collected during the methane PSA purification process. All internal needs for cooling and heat are provided by the system itself in the form of recovered waste heat from the fuel cell CHP and other onsite heat recover systems.

It is also assumed that the system at SBB is connected to the electrical power transmission grid. Continuous steady supply of biogas from SBA to SBB is also assumed because of year round digestion of manure and food waste. Therefore, biogas purification at SBA and pure methane injection into the gas holder storage at SBB is assumed to be constant year round. The fuel removal and conversion of some of stored methane from the gas holder tanks at SBB in order to do grid electricity generation is not constant but intermittent on an on-demand basis because it will be zero removal some days, rapid removal some days, and highly variable removal on spot market days due to the uncoordinated nature of the generator owner decisions and digester owner decisions when dispatching to the spot market. Onsite baseload generation at SBA is assumed to be constant because it consumes the tail gas from the methane PSA purification process with some percentage of the pure methane mixed into the tail gas to raise the energy content per unit volume (also called raising the Wobbe index of a fuel [reference personal communication

with Valerie Mason, NESI]). When the onsite generator at SBA is off, the tail gas is assumed to be flared in a catalytic converter into CO<sub>2</sub> and water.

There are five categories of energy consumers in the system, who would receive the dispatched on peak power in Figure 5.11:

- Commercial and institutional end users that trade power and natural on the spot market and consume MW electricity produced by the system.
- NYISO and FERC that transfer the interstate wholesale electric power. NYISO also coordinates the (MMBtu,MWh) forecasting, (\$/MWh) price signals, (MW) bid selection, (\$/MWh) settled prices, (\$/MWh) payout transactions and (\$) penalties of the spot market. NYISO manages MW scale ancillary services, wholesale electricity supply and demand response programs for New York State.
- The local delivery utility that transfers the electric power. The delivery utility also installs and maintains standard interconnection requirements and issues bills and cash payments from net metering.
- The local loads of the generator owner at SBB, which consume auxiliary electrical energy, thermal energy and cooling energy.
- The local loads of the digester site, farm and food processing factory at SBA, which consume onsite electrical energy, thermal energy and cooling energy.

The generator owner at SBB, in addition to selling physical units of electricity in MW and MVARs of power, also sells energy futures, options and contracts on the commodity market to the commercial and institutional users that trade power and natural gas. NYISO coordinates the requests for generator MW bids, selection of winning bids and \$/MW payout transactions. The digester owners at SBA set up tolling agreements with the Genco generator owner at SBB and pay monthly



fees to share revenue from the generator's positive spark spreads.<sup>39</sup> The priority of the designed dynamic computer executed system is to optimize the revenue of the generator owner at SBB. Thus the primary management strategy of the dynamic computer model is only from SBB, which is the generator owner's point of view.

## 5.4 Approach

Thermal fired generator owners have historically used Lagrangian relaxation techniques<sup>86</sup> and scheduling algorithms<sup>87-90</sup> to solve unit commitment and generator scheduling problems. This optimization method is done primarily to minimize the generation costs with limited fossil fuels, power line constraints, low and high generator output levels, and contracted obligations. In the simplest situation Lagrangian relaxation involves many known electrical loads connected to the grid and many known generator units with certain MW capacities that need to be committed to serve the load demands. Using Figure 5.12 as illustration, that optimization problem involves generators  $P_{G(i)}$  supplying power to end users Loads  $P_{L(j)}$  and set out to find a value of Lambda with satisfies the equations of the Lagrangian relaxation technique:<sup>86</sup>

$$\sum_{i=1}^n P_{G(i)} = \sum_{j=1}^n P_{L(j)} - \sum_{k=1}^n \lambda * Q_{(k)} \quad (5.3)$$

where:

$$\frac{\partial \lambda}{\partial P_{G(i)}} = 0$$

$P_{G(i)}$  = generator units with capacities in MW, for  $i = 1, 2, 3, \dots, I$  generator units

$P_{L(j)}$  = size of connected loads in MW, *for*  $j = 1, 2, 3, \dots, J$  loads on the grid

$Q_k$  = constraints, for  $k = 1, 2, 3, \dots, K$  constraints

## Centralized Model

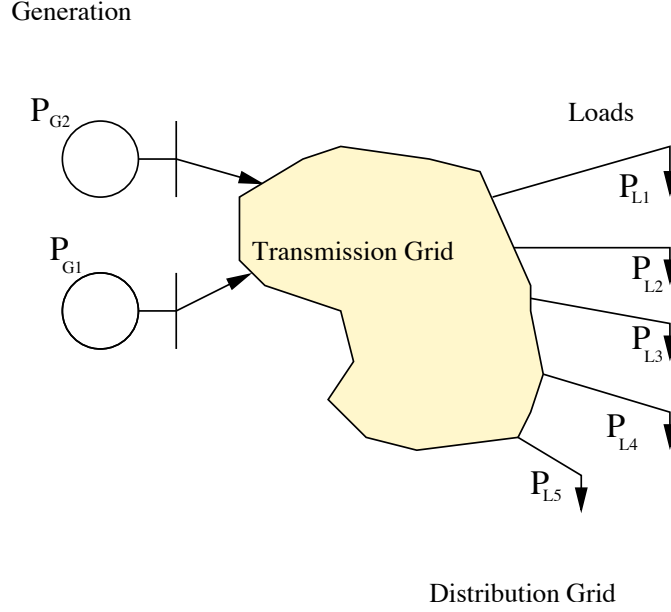


Figure 5.12: Schematic diagram of a centralized generation system used to define the variables for Lagrangian optimization of the grid.

Because the NYISO has functioned as the system bus operator, they publish the Lambda,  $\lambda$ , or marginal cost values for the winning bids. For our purposes in this research study, we use the published day-ahead market spark spread values from NYISO instead of lambda to minimize the cost of generation. Spark spread from Equation 5.1 is thus redefined as

$$SS = P_{elec} - OHR * P_{NG} \quad (5.4)$$

where:

SS = Spark Spread in \$/MWh

$P_{elec}$  = electricity price for selling power to the grid, \$/MWh

$P_{NG}$  = natural gas cost to generate Power, \$/MMBtu

OHR = operating heat rate of the MCFC or generator, MMBtu/MWh

Revenue for the Genco dispatcher at SBB comes from the spark spread payout

function in Equation 5.2, which is calculated again by:

$$\begin{aligned}\pi &= \text{Max}[(P_{elec} - OHR * P_{NG}), 0] \text{ or} \\ \pi &= \text{Max}[(MHR - OHR) * P_{NG}, 0]\end{aligned}\tag{5.5}$$

where:

$\pi$  = the payout function in \$/MWh

MHR = market heat rate =  $\frac{\text{electric spot market price } P_{elec}}{\text{natural gas spot market price } P_g}$

and the standard payout function  $\pi$  is graphically described by Figure 5.13.

Pi= payout function

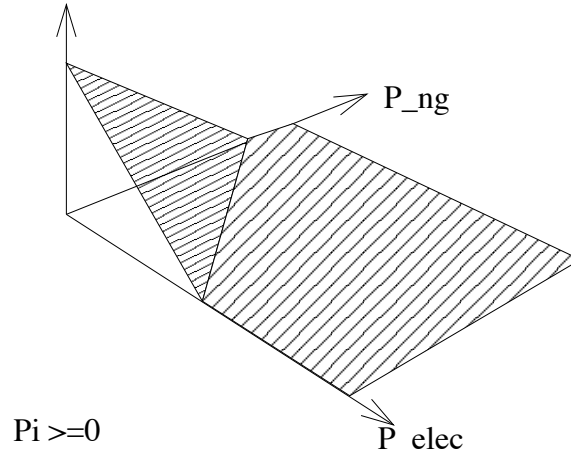


Figure 5.13: Payout function

Notice in Figure 5.13 that the revenue payout (which is the shaded surface identifying the feasible region of the graph) never occurs for negative spark spreads events because  $\pi$  returns only a positive number or zero. MHR is used as an on/off trigger because OHR is assumed to be a fixed constant number and  $P_{NG}$  doesn't vary during the month. Only the  $P_{elec}$  varies in real time and subsequently MHR changes in real time as well.

Unlike that Lagrangian relaxation method used in Equation 5.3, we can only dispatch a tiny portion of the total grid load demand (in MW) during high priced hours (in \$/MWh for specific hours) and use all of the fuel cell generating capacity

(in MW) from one generator owner at SBB, not many SBBs just one SBB in this dissertation research. Consequently, our optimization problem is different. Instead of minimizing all grid system cost to meet the all of the defined grid load, we would just minimize low wholesale electricity price yielding (in \$/MWh) generator times in order to reduce generator costs and increase the chance of high revenues.

From the static modelling chapter in Chapter 4, a steady flow of methane is assumed to continually refill gas holder storage tanks at a generator owners site. That steady flow of methane and associated cash payments are provided by tolling agreements contracts between the single generator owner at SBB and one or many digester sites at SBA which are under the tolling agreements to provide methane fuel continually to SBB. The gas holder tanks or bags supply the required methane (in MMBtu) to the peaker MCFC fuel cells, and those MCFCs dispatch electrical power (in MW units) to the grid in special 4 hour blocks according to the timeline in Figure 5.14 that sets out the sequence of activities for Gencos to participate in the NYISO day-ahead market.

Every day the generator owner at SBB receives 7 day (D, D+1, ... D+6) load forecast data (in MW demand/hour) and Day Ahead Market prices data (in hourly \$/MWh values) from NYISO and FERC. Therefore, a 7 day horizon is readily available to schedule revenue making activities. In a nutshell the aim of the generator owner at SBB is expected to follow the following three steps, which are also flow diagrammed in Figures 5.15.

1. Schedule to Minimize costs during D1, D2, D3, D4, D5, D6 and D7
2. Schedule to Maximize total collectable revenue on day D1
3. Execute the power dispatch to the grid and collect the market cleared price paid to generator owners based on those 2 above schedules and NYISO real-time data:  $SS(D1)$ ,  $P_{elec}(h)$ ,  $P_{ng}(h)$  and  $MHR(h)$

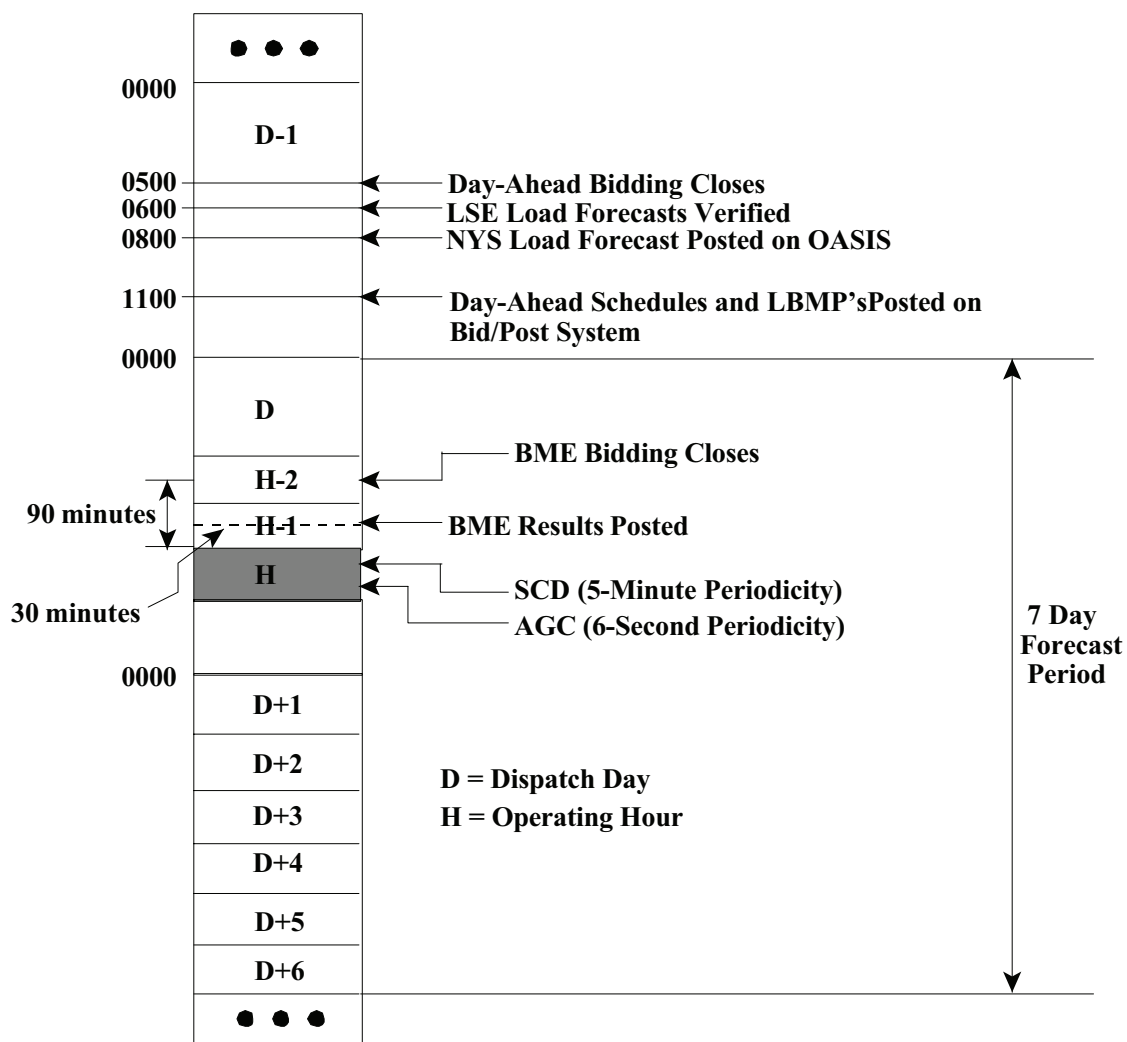
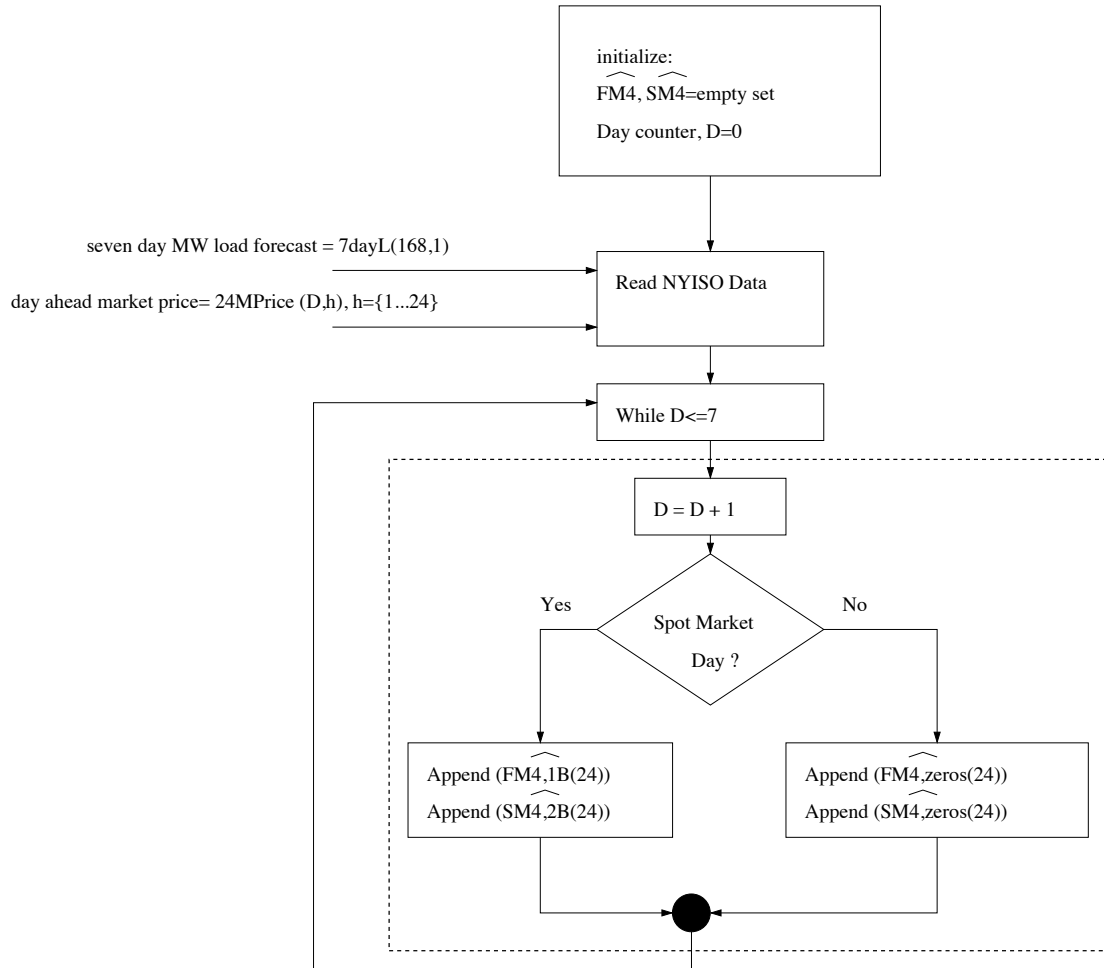


Figure 5.14: Location Based Marginal Price (LBMP) Timeline (Source: NYISO)



1B = pick location with the maximum sum of MW in a 4 hour block

2B = pick second best non-overlapping location with 2nd maximum sum of MW in a 4 hour block

Figure 5.15: Flow chart for On peak dispatch scheduling using NYISO seven day forecast data

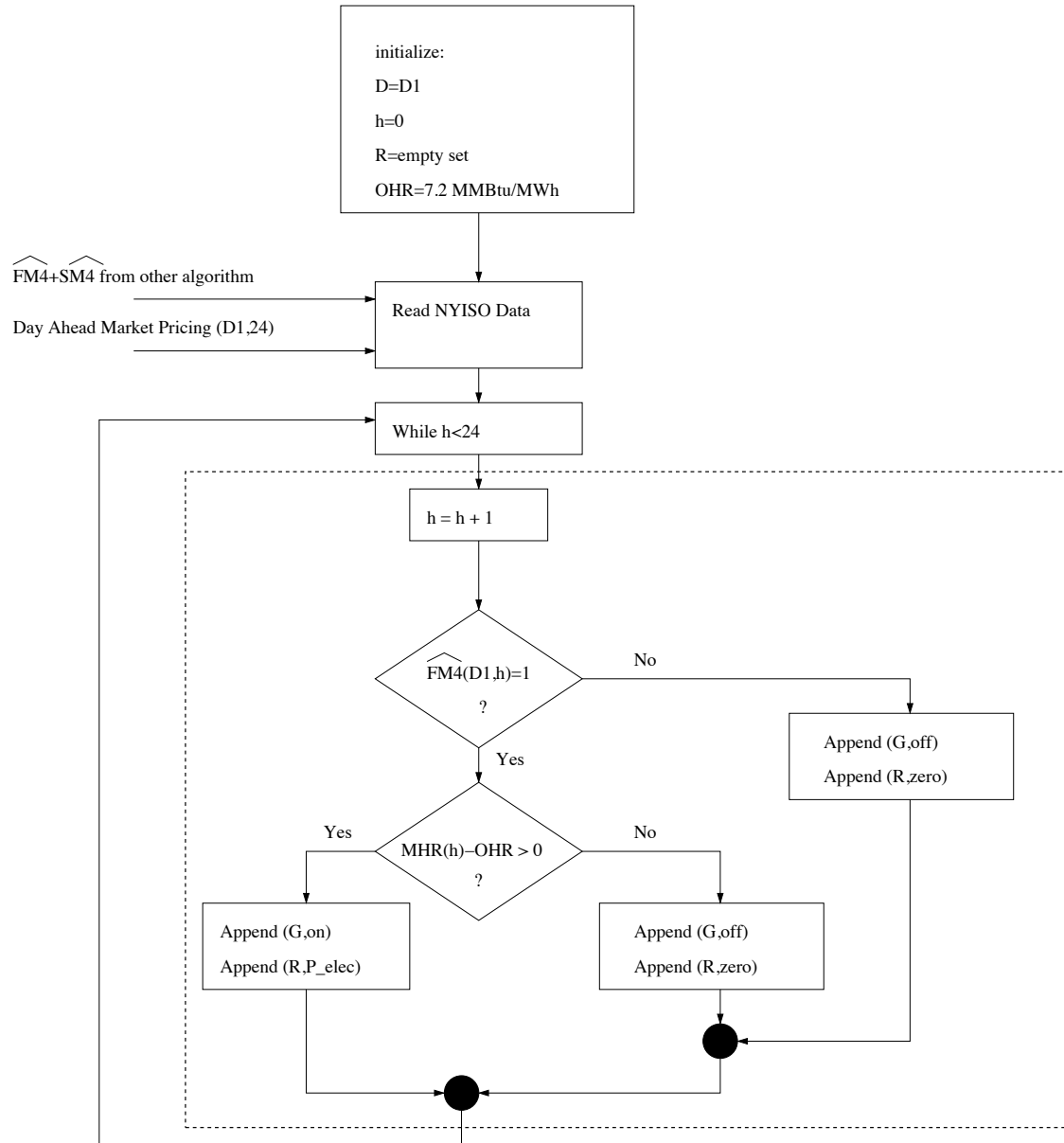


Figure 5.16: Flow chart for Onpeak scheduling using NYISO one day ahead market pricing data

An indirect method to minimize cost at the generator owner at SBB over the seven day horizon is to select only those 4 hours blocks of time each day which contain the highest forecasted MW demand. That's because the hours during (leading up to, and following after) the highest MW demand times tend to also have the highest hourly market heat rate (MHR) because they typically have the highest \$/MWh Location based marginal prices(LBMP). Vectors  $\widehat{FM4}$  and  $\widehat{SM4}$  contain the on/off unit commitment pattern for the 168 hours during the seven day period.  $\widehat{FM4}$  contains the 4 hour block with the highest sum of load demand MW and  $\widehat{SM4}$  contains the second best 4 hour block for the second best sum of demand MW load. These two vectors  $\widehat{FM4}$  and  $\widehat{SM4}$  are binary vectors,  $\{0,0,0,...,1,1,1,1,...,0,0,0\}$  and are 168 bits long.

$$\begin{aligned}\widehat{FM4}(D) &= \text{location of the maximum sum of four loads on each day } D \\ &= \max(L_h + L_{h-1} + L_{h-2} + L_{h-3}) \text{ for } h = 0 \text{ to } 24 \text{ on each day } D \text{ and} \\ \widehat{SM4}(D) &= \text{location of the second best maximum sum of four Loads on day } D \\ &= \max(L_h + L_{h-1} + L_{h-2} + L_{h-3}) \neq \widehat{FM4}(D) \text{ for } h = 0 \text{ to } 24 \text{ on each } D\end{aligned}$$

Multiplying the generator MW output level by  $\widehat{FM4}$  or  $\widehat{SM4}$  gives the eligible onpeak generation period and related fuel consumption schedule for a 7 day horizon. This potential schedule, however, does not guarantee that there will be adequate fuel supply from the gas holder tank to meet that schedule. Therefore, the improved algorithm for solving the problem would involve first minimizing the high cost generation hours over the 7 day horizon subject to bids placed only during onpeak hours and during time that have adequate fuel levels. Next is the maximization of total revenue for the day ahead market using NYISO and FERC posted schedule prices by using the algorithm summarized in the Figure 5.16 flow chart. This would be subject to the gas holder inventory and the refill rate. In the unlikely event that the refill volume is greater than the consumption schedule, it



can be used for high heat energy consuming periodic tasks at SBB such as pelleting or drying of digested solids; or that excess storable fuel energy can be exported off-site for use in vehicles and heating fuel; or that excess fuel used to make other biofuels such as compressed NG (CNG), Liquified NG (LNG), biobased dimethyl ether (bioDME), hydrogen or biomethanol. These algorithms for making power dispatch decisions are shown in Figures 5.15 and 5.16. To summarize, the overall approach for running the dynamic model is described in Figure 5.17 below.

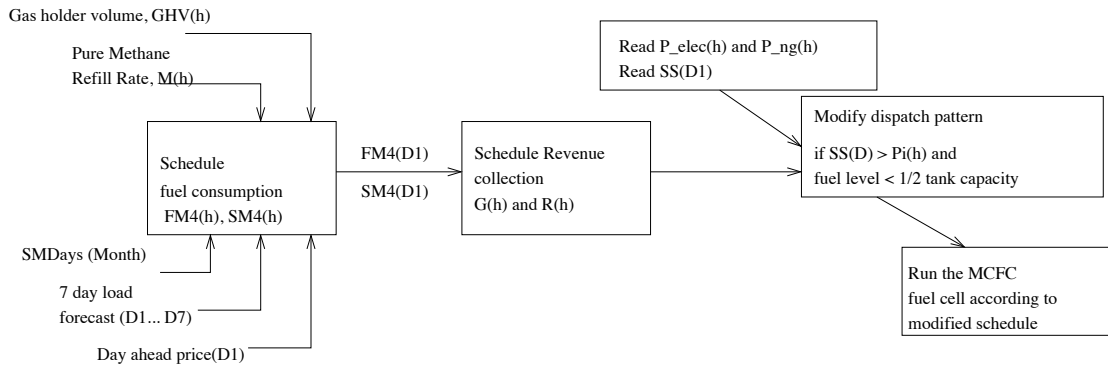


Figure 5.17: Flow chart showing extra details in the chain of events for daily power dispatch decisions in the OpTiGaS dynamic computer model

To utilizes this payout function, we download and parse NYISO and FERC data for 7 day load forecast and day ahead location based prices into simpler 168 hour vector and 24 hour vector respectively. We download the scheduled spot market days and construct a 31 day vector SMDays (Month). We also keep track of the pure methane volume in the gas-holder bags GHV(h) and the refill rate M(h) from the digester and purification modules. The strategy is to combine the parameters and variables into a dynamic computer model called the Onpeak Time Generation and Storage (OpTiGaS) model for dispatching onpeak power to the grid. It builds on top of the static Koenig network models for digester gas production and methane storage from the previous chapter, Chapter 4. The goal is to use algorithms and linear programming techniques to conduct risk management

and maximize revenue. If it is possible to capture more than 50% of the theoretical revenue from spot market with minimal megawatt scale generation, then there will be a chance to find a combination of parameters, variables and scheduling methods with OpTiGaS that would yields that rewarding outcome!

## 5.5 Objective Function

The formulation of the objective function is broken down into three steps:

### Step I

Minimize dispatch and fuel consumption scheduling for the 7 day horizon, D1, D2, D3, D4, D5, D6, and D7 with 168 hours to only those 4 hours blocks with the highest onpeak MW load during a 24 hour period:

$$\text{DispatchSchedule}(168 \times 1) = \text{sumProduct}(\widehat{FM4}, \text{Spot Market Days}) \text{ or}$$

$$\text{DispatchSchedule}(168 \times 1) = \text{sumProduct}(\widehat{FM4} + \widehat{SM4}, \text{Spot Market Days})$$

where:

$\widehat{FM4}$  = vector containing location of the 4 hour block with the highest loads values

$\widehat{SM4}$  = vector containing 2nd best locations for a 4 hour block

SpotMarketDays = binary vector depicting the spot market days during the next 168 hrs as 1's for ON or 0's for OFF those specific hours

### STEP II

Maximize Total Revenue scheduling using the 1 day horizon, day (D1),

$$\pi_{D1} = 1MW * 1hr * \text{Spark Spread}(D1) * \text{Sumproduct}[\text{Dispatch Schedule}(D1),$$

*Positive Spark Spread Query(D1), Sufficient Fuel Level in Gas Holder Query]*

subject to:

D1 is a vector of length 24

positive spark spread(D1(h)) $\geq$  \$100 for h = 1...24;

### STEP III

Run the 1MW powerplant based on the two schedules G(h) and R(h) as well as day ahead NYISO SS(D1) within stored fuel constraints

and monitor the hourly prices  $P_{elec}(h)$ ,  $P_{ng}(h)$

subject to  $\pi = \max[MHR(h)-OHR)P_{ng}(h),0]$

and  $\pi(h) \geq SS(D1)$

gas holder fuel tank level (h) < 1/2 full tank volume.

Therefore, overall objective function is:

=====

for h=1 to 24 {

Maximize total day's payout function on day D1 from

consuming fuel and dispatch power to the grid

Append Revenue(h)=Revenue R(h-1) + scheduled\_R(h)

or

Append Revenue(h)=Revenue R(h-1) +  $\pi(h)$

i.e.

Append Revenue(h)=Revenue R(h-1) + max[scheduled\_R(h),  $\pi(h)$ , settled NYISO

LBMP price(h)]

where the revenue payout function  $\pi(h)=\max[MHR(h)-OHR)P_{ng}(h),0]$

} end for

=====

## 5.6 Testing the Model with Training Sets

### Calculations by hand

Assume that we are starting with the Tuesday July 6, 2010 spark spreads, and have a Genco representing SBB that is piping methane from multiple biogas digesters from SBA into gas holder storage tanks at SBB. The Genco dispatcher is also keeping track of the NY Zone J spark spreads by computer queries (did not have data for Zone C (Central New York) to do calculations at this point therefore, Zone J (New York City, NYC) was substituted to do the scenario instead). That Tuesday followed a 2-day holiday, that means methane storage was increasing steadily and not being depleted for electricity for 4 days straight. Looking at Figure 5.18, the marginal heat rate, or market heat rate (MHR), = 25.12 MMBtu/MWh and the operational heat rate (OHR) is 7.26 MMBtu/MWh for the 1.4 MW MCFC fuel cell. Because the MHR 25 is greater than the OHR 7 then the Genco dispatcher must sell power when  $P_{elec} \geq \$91.44/\text{MWh}$ .

The spark spread of the generator falls into the 7k column= 91.44. To double check, the calculation for the spark spread= Payout function,  $\pi = \max((\text{MHR} - \text{HR})P_{ng}, 0) = \max((25.124 - 7) * 5.045, 0) = 18.124 * 5 = 91.44$ . So the Genco dispatcher would keep track of the MHR, which is also sometimes called the real time strike price =  $P_{elec}/P_{ng}$ . The NG price was locked in from the previous months at around \$5/MMBtu with forward NG price contracts for the entire month as shown in Figure 5.19. Then based on day ahead electric spot market prices with its hourly interval, the spot market heat rate, MHR, is shown in Table 5.1.

Based on the spark spread values for Gencos (with OHR above 7000) of \$91.44 alone, the cogen would stay online for 12 hours in NYC. However, based on MHR above \$25, the cogen is ONLINE for 7 hours in NYC zone. The Genco dispatcher

## Spark spreads for Jul 6

	Marginal	Spark spreads				
	heat rate	@7k	@8k	@10k	@12k	@15k
<b>East</b>						
Mass Hub	18787	60.23	55.12	44.90	34.68	19.35
N.Y. Zone-G	21344	72.58	67.52	57.40	47.28	32.10
N.Y. Zone-J	25124	91.44	86.39	76.30	66.21	51.08
N.Y. Zone-A	14228	36.07	31.08	21.10	11.12	-3.85
Ontario*	11254	22.49	17.20	6.63	-3.94	-19.80
PJM West	21223	71.54	66.51	56.45	46.39	31.30
TVA, into	11335	20.46	15.74	6.30	-3.14	-17.30
<b>Central</b>						
Cinergy Hub	12461	26.41	21.57	11.90	2.23	-12.28
NI Hub	13218	28.70	24.08	14.85	5.62	-8.23
Entergy, into	10608	16.46	11.90	2.78	-6.35	-20.04
ERCOT, Houston	9514	11.63	7.00	-2.25	-11.50	-25.38
<b>West</b>						
Mid-C	9659	10.23	6.38	-1.31	-9.00	-20.54
Palo Verde	10198	13.07	8.98	0.81	-7.36	-19.62
NP15	9994	12.28	8.18	-0.03	-8.23	-20.54
SP15	9581	10.78	6.60	-1.75	-10.10	-22.63

\*Ontario prices in Canadian dollars. \*\*Spark spreads are reported in (\$) and Marginal heat rates in (Btu/kWh)

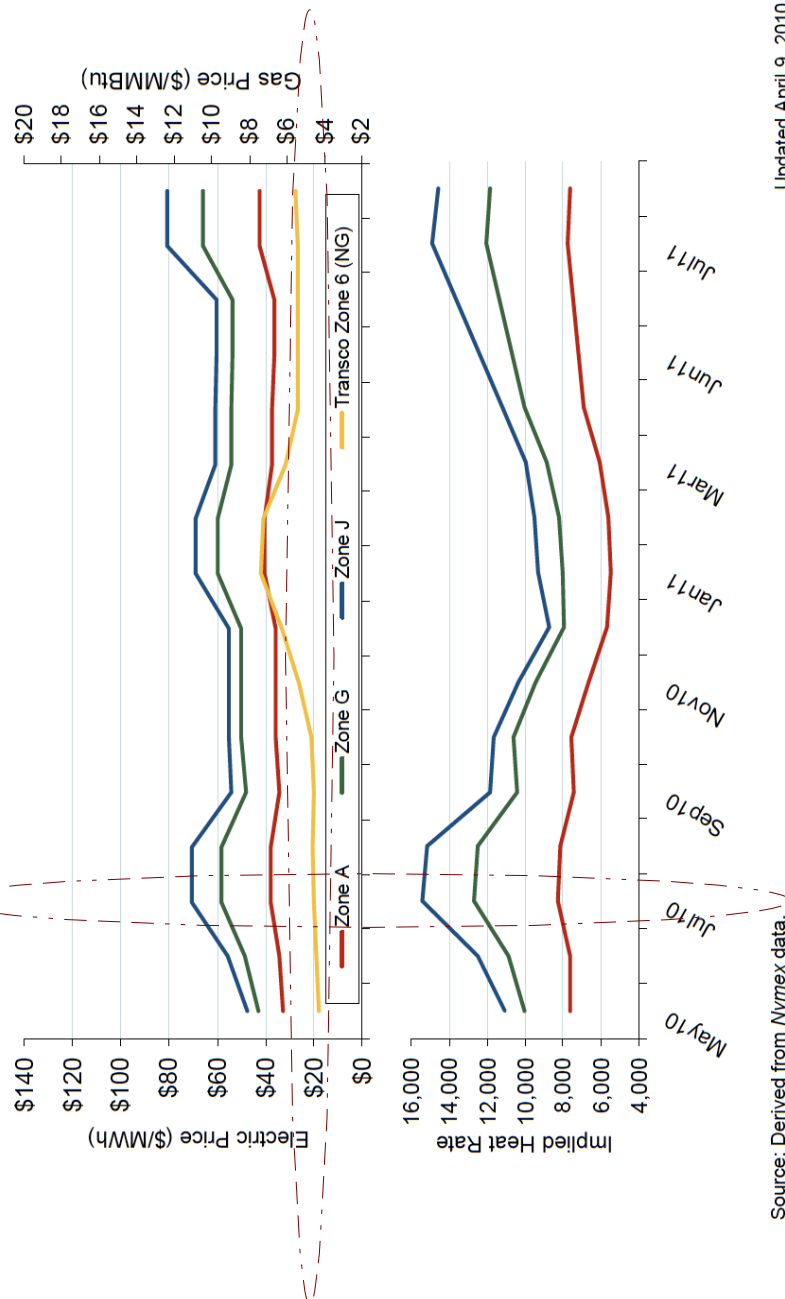
<b>Citygates</b>						
Chicago city-gates	4.615	+0.140	4.55-4.65	4.59-4.64	1088	175
Consumers city-gate	4.785	+0.195	4.74-4.88	4.75-4.82	173	35
Mich Con city-gate	4.815	+0.175	4.77-4.89	4.79-4.85	597	73
PG&E city-gate	4.245	-0.030	3.98-4.35	4.15-4.34	941	127
Florida city-gates	5.325	+0.005	5.12-5.40	5.26-5.40	68	4
Algonquin, city-gates	5.100	+0.260	5.05-5.22	5.06-5.14	346	61
Tennessee, zone 6 del.	5.120	+0.285	5.00-5.27	5.05-5.19	370	63
Iroquois, zone 2	5.180	+0.285	5.10-5.26	5.14-5.22	196	32
Tx. Eastern, M-3	5.060	+0.280	4.99-5.18	5.01-5.11	524	108
Transco, zone 5 del.	4.965	+0.240	4.85-5.04	4.92-5.01	99	9
Transco, zone 6 non-N.Y.	5.030	+0.260	4.98-5.13	4.99-5.07	112	29
Transco, zone 6 N.Y.	5.045	+0.275	4.99-5.14	5.01-5.08	636	100
Kern River, delivered	4.080	-0.080	4.02-4.15	4.05-4.11	296	42
SoCal Gas, city-gate	4.215	+0.035	4.03-4.32	4.14-4.29	800	95

\*NOTE: Price in C\$ per gJ; C\$1=US\$0.9391

Volume in 000 MMBtu/day

Figure 5.18: Selecting the Market heat rate and natural gas spot price for Zone J (New York City, which is also NG Transco zone 6) from Forecast data.

## New York Electric Forward Price Curves and Implied Heat Rates



Source: Derived from Nymex data.

Updated April 9, 2010

Figure 5.19: Gas futures price for Transco Zone 6 (New York City, which is also electricity Zone J). The highlighted price for July 2010 in the overlapping ovals is \$5/MMBtu

Table 5.1: Day Ahead Marginal price(\$/MWh) and Market heat rate (MMBtu/MWh) for Zone J and Transco Zone 6 (New York City) over a 24 hour period on July 6, 2010

	hr	1	2	3	4	5	6	7	8	9	10	11	12
Day ahead \$/ MWh		60.34	45.45	41.94	40.49	40.64	43.87	48.18	68.01	72.44	77.63	96.77	108.84
NG\$/ MMBtu		5	5	5	5	5	5	5	5	5	5	5	5
MHR		12.07	9.09	8.39	8.1	8.13	8.77	9.64	13.6	14.49	15.53	19.35	21.77
	hr	<b>13*</b>	<b>14*</b>	<b>15*</b>	<b>16*</b>	<b>17*</b>	<b>18*</b>	<b>19*</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
Day ahead \$/ MWh		129.52	153.2	166.73	187.27	185.94	175.2	137.31	110.85	105.05	94.6	84.62	72.92
NG\$/ MMBtu		5	5	5	5	5	5	5	5	5	5	5	5
MHR		25.9	30.64	33.35	37.45	37.19	35.04	27.46	22.17	21.01	18.92	16.92	14.58

is advised to pick this option that stays online for 7 hours plus one extra hour to give the best 8 hour block, 12:00 to 20:00.

The real time data in Figure 5.20 showed that the day ahead forecasted loads and prices during the onpeak time were exceeded by actual onpeak loads and prices, indicating high economic incentive price signals would have been sent to the independent power producing (IPP) Genco dispatchers.

What has been learned from manually doing this spot market training set? It was learned that it is important to lock in the NG futures prices in order to interpret the spark spread data properly. Notice the NG spot market price and futures price were identical at \$5/MMBtu. If we bought ng cheaper then the MHR would be higher and we could cogenerate lots more hours to make additional revenue.

From Table 5.1, the resulting sum of the expected revenue for the top 8 hour blocks of LBMP is  $1.4 \text{ MW} \times 1 \text{ hr} \times \text{sum}[P1, P2, \dots P8] = \$1,744.30$ .

## Calculations and Results by Algorithm

When the computer model is used to determine onpeak dispatch on Tuesday July 6th, it starts off with a 6 day forecast. For example the 6 day forecast received on July 1st showed the expected load in Figure 5.21. The fm4 and sm4 vectors were chosen to minimize the fuel consumption for the upcoming days July 2 to July 7 including the two day holidays Sunday July 4 and Monday July 5 when the market is closed.

Also using the Day-Ahead LBMP price (D1) data for 7/6/2010, dispatch blocks FM4(D1) and SM4(D1) are selected based on best prices in a 4-8 hour block

Expected revenue from the day ahead-market =  $1.4\text{MW} \times 1 \text{ hr} \times \$/\text{MWh} \times \text{sumproduct}(\text{unitson}(h), \text{LBMP}(h)) = \$1,744.43$  which is the same answer as the calculation done by hand. Using all 31 day-ahead values in July 2010, the total ex-



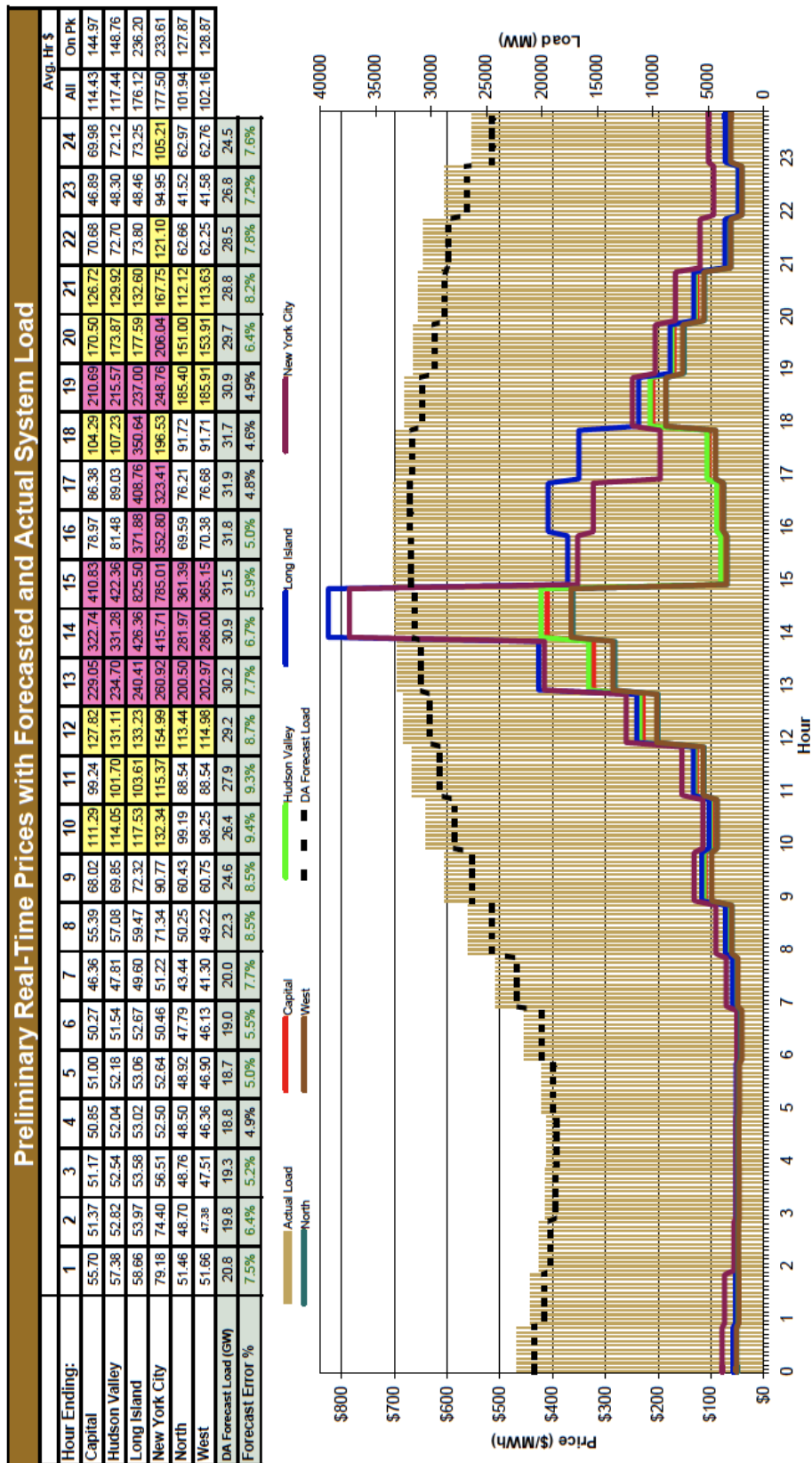


Figure 5.20: Sample Real-Time Prices with Actual and Forecast Loads for Zone J (New York City) on July 6, 2010, Source: FERC 2010

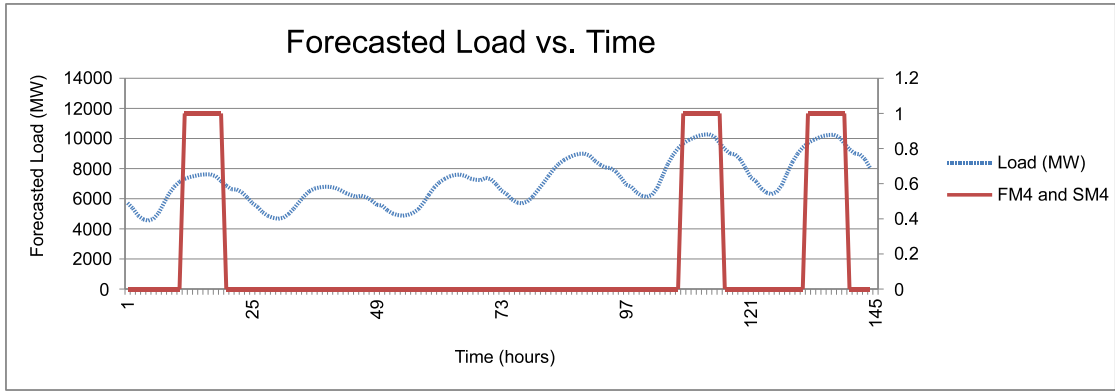


Figure 5.21: Six Day Forecast for New York July 1, 2010

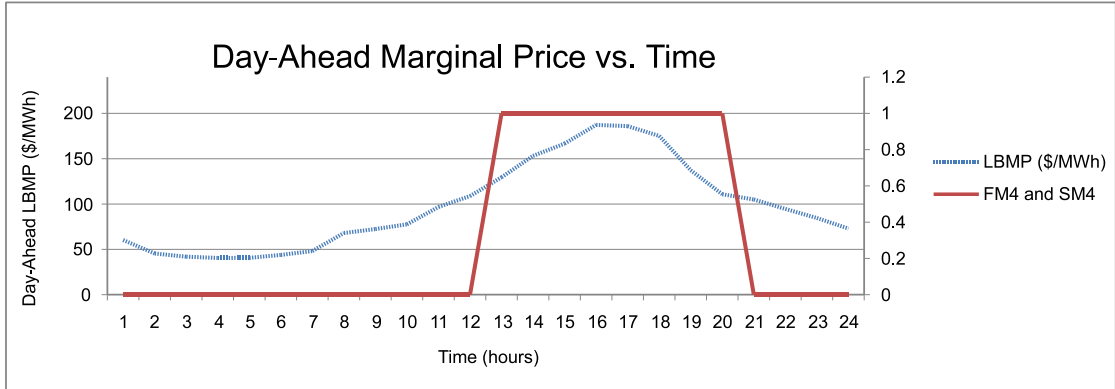


Figure 5.22: Day Ahead for New York July 1, 2010

Table 5.2: Selection of FM4 and SM4 to minimize hours with low revenue

Time	1	2	3	4	5	6
LBMP (\$/MWh)	60.34	45.45	41.94	40.49	40.64	43.87
FM4 and SM4	0	0	0	0	0	0
Time	7	8	9	10	11	12
LBMP (\$/MWh)	48.18	68.01	72.44	77.63	96.77	108.84
FM4 and SM4	0	0	0	0	0	0
Time	<b>13*</b>	<b>14*</b>	<b>15*</b>	<b>16*</b>	<b>17*</b>	<b>18*</b>
LBMP (\$/MWh)	<b>129.52</b>	<b>153.2</b>	<b>166.73</b>	<b>187.27</b>	<b>185.94</b>	<b>175.2</b>
FM4 and SM4	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>
Time	<b>19*</b>	<b>20*</b>	21	22	23	24
LBMP (\$/MWh)	<b>137.31</b>	<b>110.85</b>	105.05	94.6	84.62	72.92
FM4 and SM4	<b>1</b>	<b>1</b>	0	0	0	0

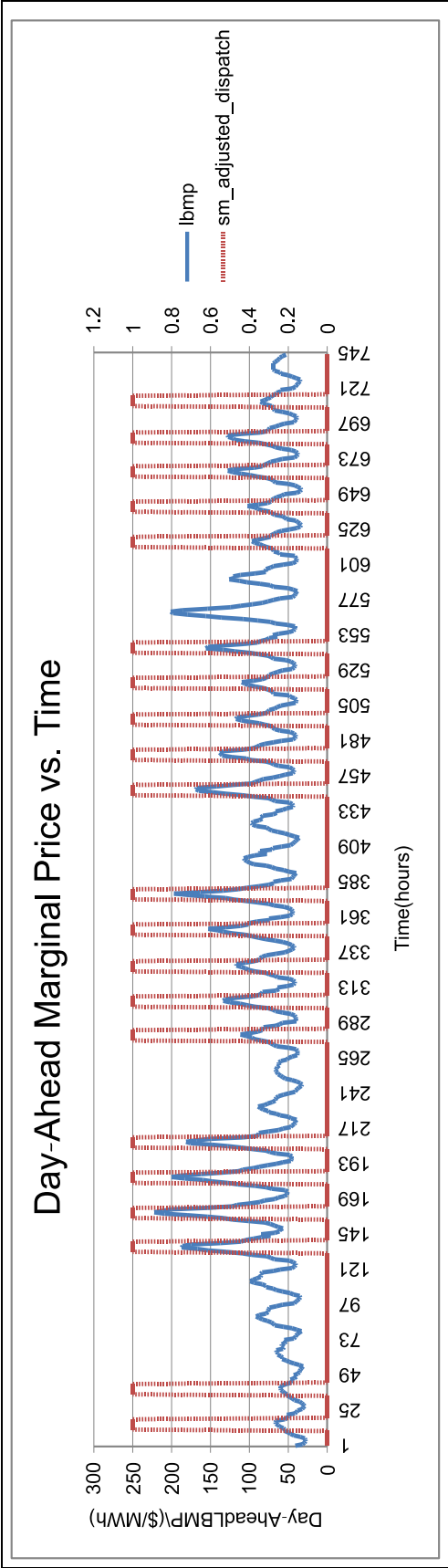
pected revenue related to the dispatch results in Figure ?? is \$26,906.60 assuming no fuel availability constraint. The fuel constraint is address in the next chapter. Compared to the total theoretical revenue during the spot market based on historical data, The graphs in Figure 5.23 (a) and (b) shows that 58.8% of the theoretical on peak only revenue was captured, if I dispatched according to the price signals, that is \$26,906 out of \$45,696. In comparison the net metering would yield \$5,952 in revenue assuming \$0.02/kWh running a 400 kW engine genset which sized for the 2,000 cows dairy.

## **5.7 Initial Test Runs of the OpTiGaS System to Generic Large and Small Farms in Central NY**

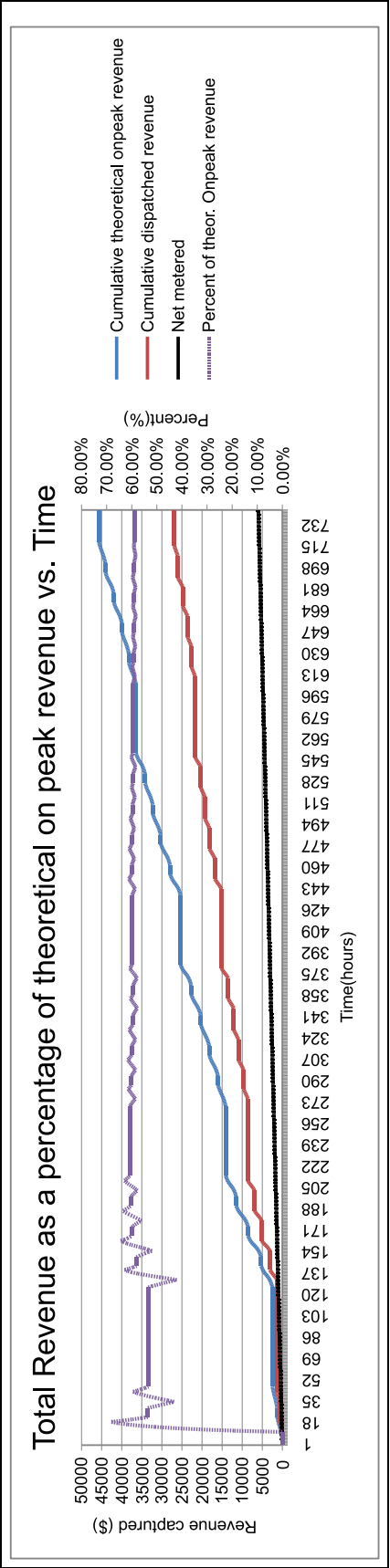
### **5.7.1 Generic Large Farm**

Located in Upstate New York, the Large Generic Dairy has 2,000 milking cows and operates a digester site that sell power to the power utility company.

The Optigas static model was used to determine the projected improvement to the Generic2000 dairy's exported electricity. Mathematically we solved  $A \cdot x = b$  shown below where the technology coefficients matrix  $A$ , multiplied by vector of



(a) 31days-july-2010-NYC



(b) 31days-percent-theo-captured-july2010-NYC

Figure 5.23: Expected revenue when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model

flow variables, x, is equal to the vector of known input-output quantities, b.

$$\begin{bmatrix} \frac{1}{k_{(1,P1)}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{k_{(2,P1)}} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{1}{k_{(3,P1)}} & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & -1 & 0 \\ 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(1,P3)}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(2,P3)}} \end{bmatrix} \cdot \begin{bmatrix} y_{1,P1} \\ y_{2,P1} \\ y_{3,P1} \\ y_{1,P2} \\ y_{2,P2} \\ y_{1,P3} \\ y_{2,P3} \end{bmatrix} = \begin{bmatrix} y_{0,P1} \\ y_{0,P1} \\ y_{0,P1} \\ 0 \\ 0 \\ y_{0,P3} \\ y_{0,P3} \end{bmatrix} \quad (5.6)$$

---

---

Determinant of A = 0.59845619

Stimulus variables input vector, b=

300,000.00

300,000.00

300,000.00

0.00

0.00

1.40

1.40

Solution output vector, x=

67,596.09

289,014.08

101,894.13

67,596.09

10.16

10.16

4.37

---

---

The interpretation of vector x are:

$y_{1,P1} = 67,596.09 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA,  
 $y_{2,P1} = 289,014.08 \text{ lbs}$  of digester slurry per day leaves the digester as effluent  
 $y_{3,P1} = 101,894.13 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously,  
 $y_{3,P1} = 67,596.09 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage,  
 $y_{1,P2} = 10.16 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas,  
 $y_{2,P2} = 10.16 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and  
 $y_{1,P3} = 4.37 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

---



---

Solution to 7 days of refilling the tank at 46.94 cfm  
 with pure methane is :

$$473,172.61 \text{ ft}^3 \text{ or } 13,398.74 \text{ m}^3$$

Compare 7 days of tank refilling 13,398.74 m<sup>3</sup>, with the following MCFC gas holder tank sizes :

4hrsx5d	8hrsx5d	4hrsx7d	8hrsx7d
6,189.51 m <sup>3</sup> , 12,379.02 m <sup>3</sup> , 8,665.31 m <sup>3</sup> and 17,330.62 m <sup>3</sup>			

Also the onsite generator size , based on tailgas 70.76 cfm is :  
 0.1767 MW

---



---

The OpTiGaS static model showed that the Generic2000 digester site and generator company with 2,000 cows and a 1.4 MW fuel cell system would require a 13,398.74 m<sup>3</sup> (473,172.61 ft<sup>3</sup>) system of gas holder tanks with a continuous refill

rate of 46.94 cfm of pure methane for grid power export.

On the generic farm itself, 70.76 cfm of mixed tail gas could run a fuel cell that generated 180 kW of power continuously. The 13,398.74 m<sup>3</sup> gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 1.4 MW power and 8 hrs/day x 5 days x 1.4 MW to the spot market. The flow chart in Figure 5.24 shows the static network model for the Generic2000 farm.

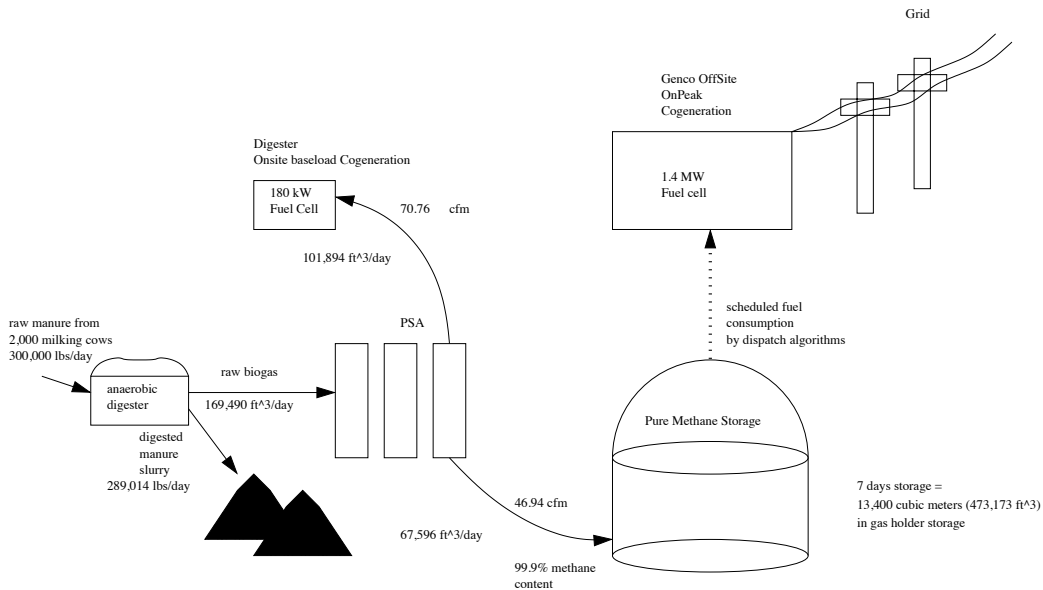


Figure 5.24: Resulting Static Model Flow Chart for the Large Generic Farm with 2,000 Milking Cows (Generic2000)

The power dispatch to the spot market using the 1.4 MW system connected to the 13,398.74 m<sup>3</sup> gas holder storage was simulated using the OpTiGaS dynamic model. Data from NYISO in July 2010 was used as a training set to see specifically the Day Ahead Marginal price data. It is observed in Figure 5.25 that the 1.4 MW for 8 hours/day on spot market days from the large Generic 2000 cow dairy would lead to under capacity problems with the gas holder starting on day 22 (528th hour) of 31 days which meant that the generators would be forced to shut down and go offline from the grid regardless of the dispatch commitment with NYISO. They would incur a penalty for not dispatching. Also dispatching 1.4 MW for 4

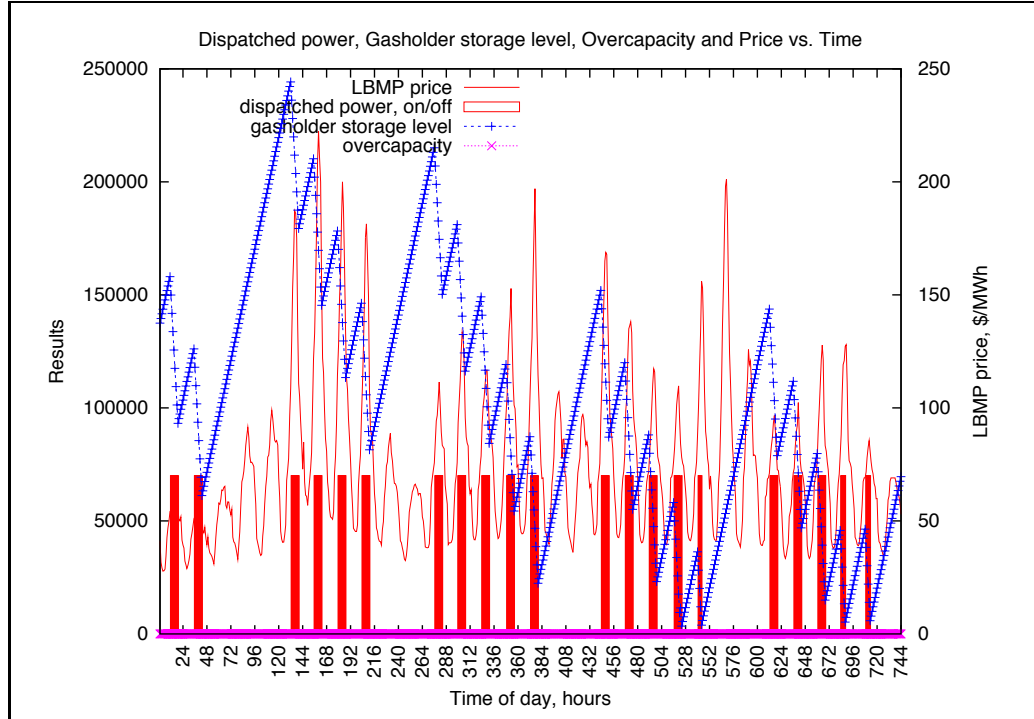
hours/day on spot market would eventually lead to overcapacity problems with the gas holder on Day 17.

Running the fuel cell for 8hrs/day x 1.2 MW instead provided a remedy to methane consumption while maintaining gas storage levels that didn't cause under capacity problems of the gas holder system. The revenue collected by the Generic2000 cow Dairy and the Genco, shown in Figure 5.27, was calculated to be around \$23,063 for July 2010, representing 59% of the theoretical spot market revenue, \$39,168.

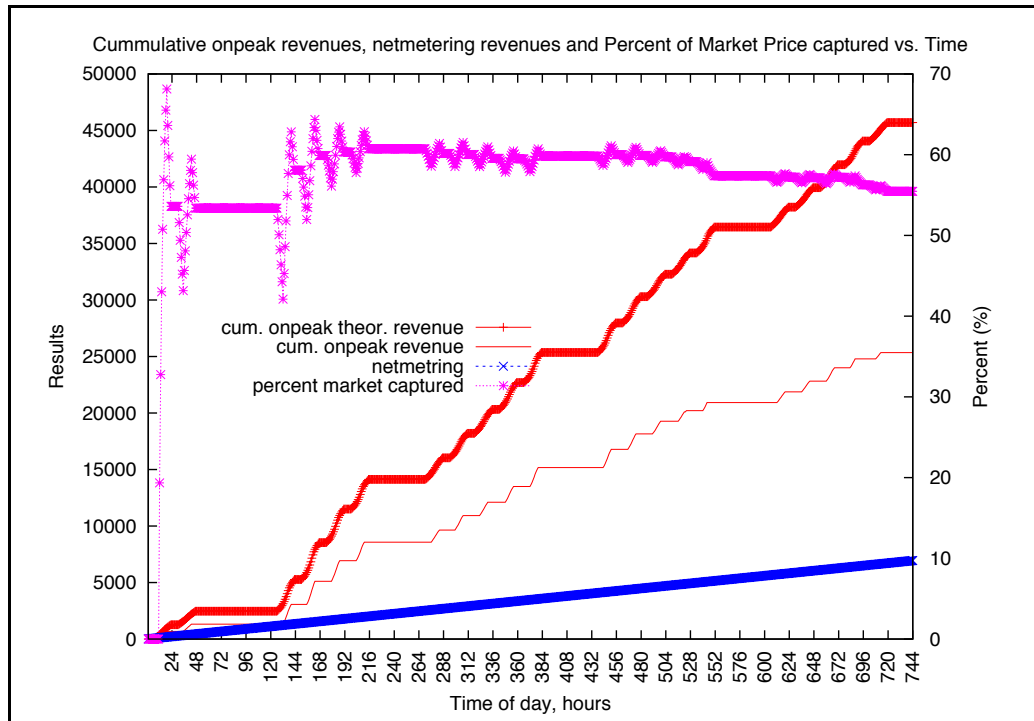
Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system.

1. Biomass input = biogas from 2,000 milking cows
2. Gas holder size 13,398.74 m<sup>3</sup> (473,172.61 ft<sup>3</sup>) for pure methane = inject and wheel the pressurized natural gas through the local pipeline or fill six 2,000 m<sup>3</sup> gas holder tanks with some excess gas or two 6,000 m<sup>3</sup> gas holder tanks with some excess gas
3. Fuel cell size for onpeak generation = 1.4 MW with the flexibility to throttle up or down individual units to 1.1 MW by reducing unneeded generation capacity as necessary or as per dispatch schedule.
4. In July 2010 generate power for 8hrs/day per spot market day based on the OpTiGaS scheduled dispatching
5. Fuel cell size for local onsite generation 180 kW (a 300 kW MCFC running on dilute methane in the tail gas)
6. Pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.



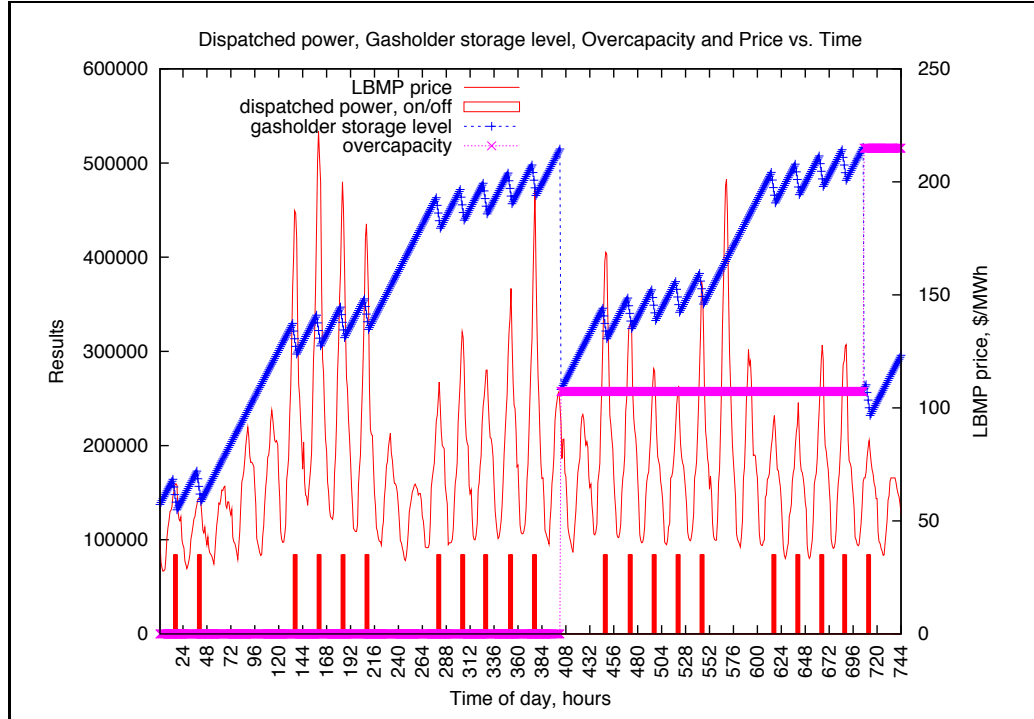


(a) Generic Dairy 2,000 cows, 1,400 kW and 8 hrs

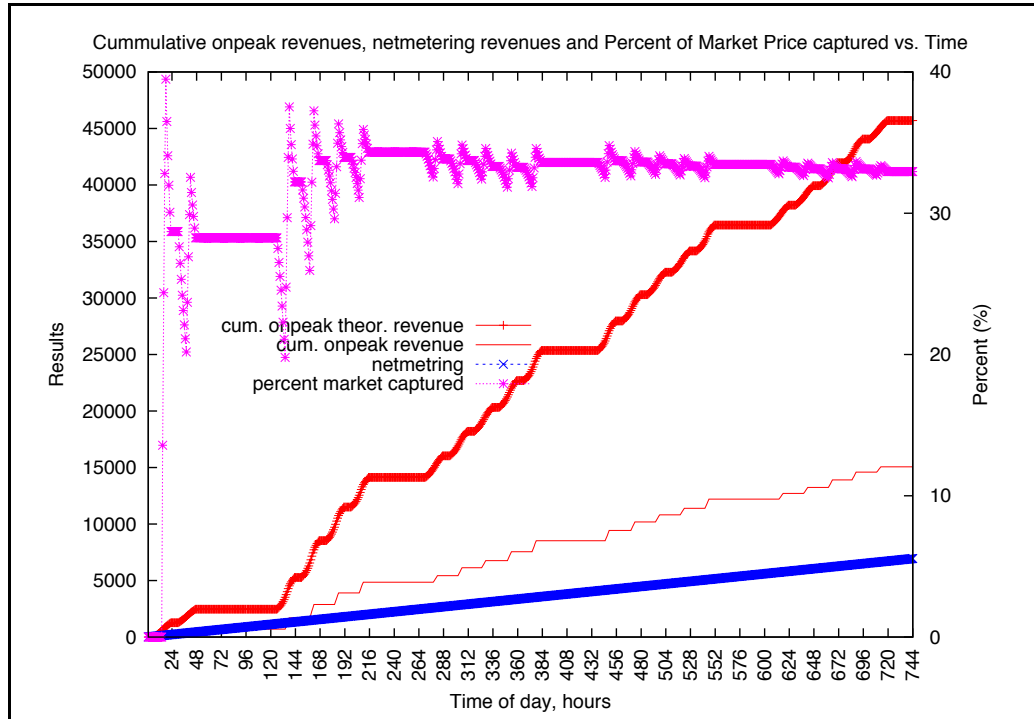


(b) Generic Dairy 2,000 cows, 1,400 kW, 8 hrs and revenue

Figure 5.25: Expected revenue at the Generic 2000 milking cows Dairy when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 46.94 cfm (67,596.09 ft<sup>3</sup>/day) of digester biogas, 1.4 MW and 8 hrs

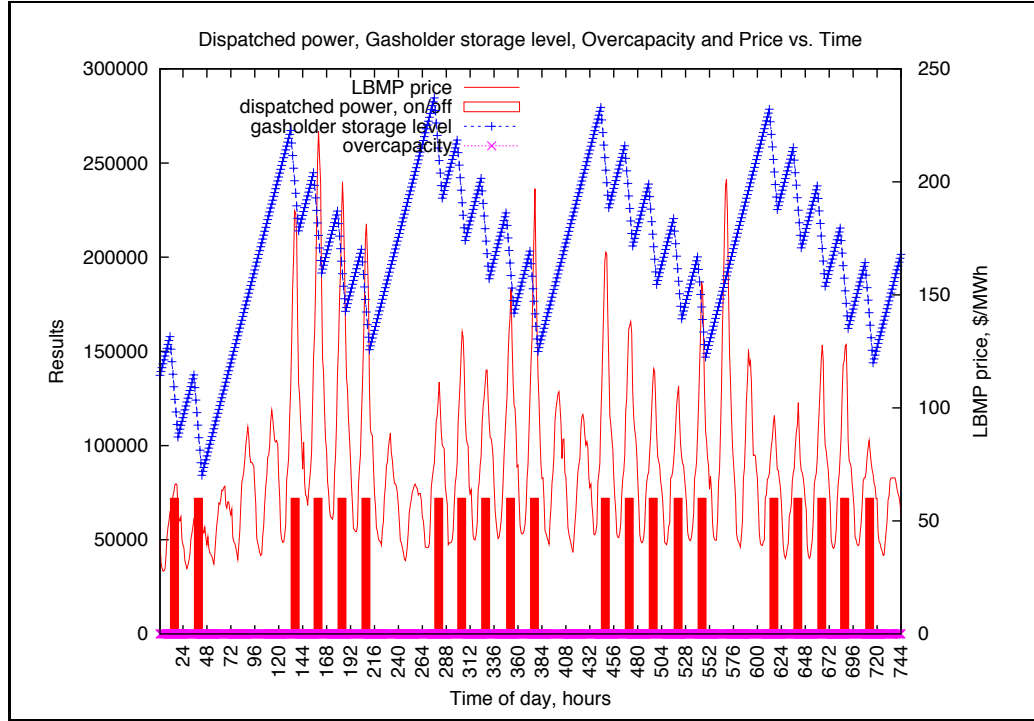


(a) Generic Dairy 2,000 cows, 1,400 kW and 4 hrs

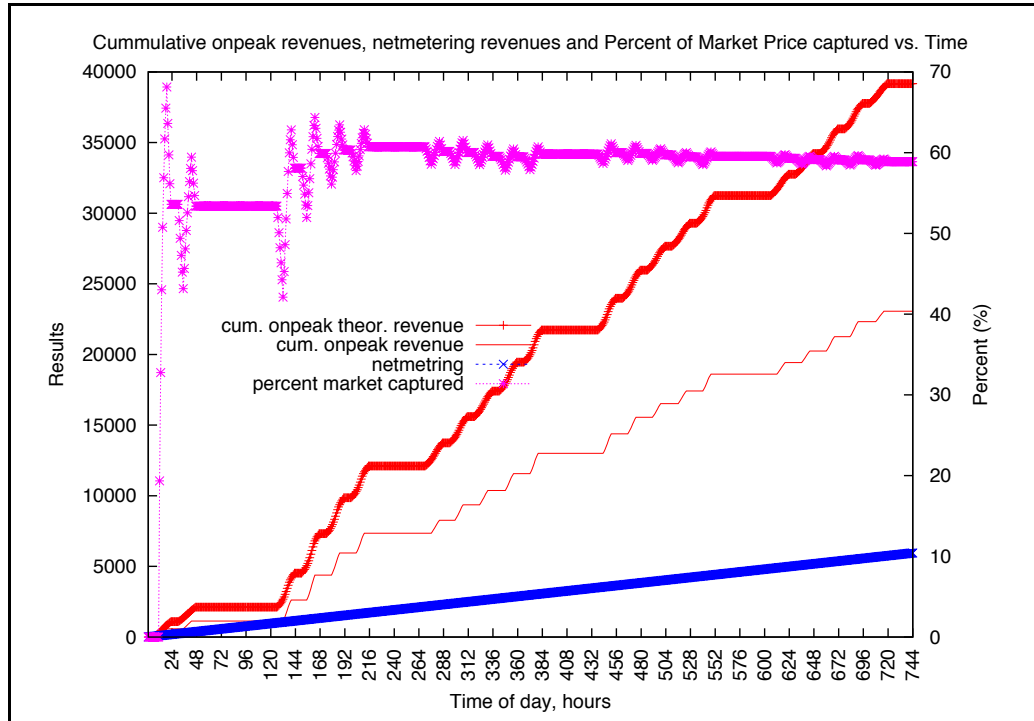


(b) Generic Dairy 2,000 cows, 1,400 kW, 4 hrs and revenue

Figure 5.26: Expected revenue at the Generic 2,000 milking cows Dairy when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 46.94 cfm (67,596.09 ft<sup>3</sup>/day) of digester biogas, 1.4 MW and 4 hrs



(a) Generic Dairy 2,000 cows, 1,200 kW and 8 hrs



(b) Generic Dairy 2,000 cows, 1,200 kW, 8 hrs and revenue

Figure 5.27: Expected revenue at the Generic 2,000 milking cows Dairy when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 46.94 cfm (67,596.09 ft<sup>3</sup>/day) of digester biogas, 1.2 MW and 8 hrs

7. Sign a tolling agreement between the Genco and Patterson Farm
8. The farm successfully fulfilling the Standard interconnection requirement document with local utility for net metering
9. The Genco successfully accepted to sell whole sale power to the NYISO spot market as a market participant
10. Internet downloading of spot market data to enable bids into the day ahead market and six day load forecast data
11. Natural gas pipeline as a backup in case of the rare situation of insufficient biogas in the gas holder

### 5.7.2 Generic Small Farm

Located in Upstate New York, the Small Generic Dairy is assumed to have 80 milking cows and operates a digester site that sell power to a local utility such as NYSEG, RG&E or the National Grid Company.

The Optigas static model was used to determine the projected improvement to the Generic80 Dairy's exported electricity.

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Determinant of A = 0.59845619

Stimulus variables input vector , b=

12,000.00

12,000.00

12,000.00

0.00

0.00

0.07

0.07

Solution output vector , x=

2,703.84

11,560.56

4,075.77

2,703.84

0.51

0.51

0.22

---

The interpretation of vector x are:

$y_{1,P1} = 2,703.84 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA,

$y_{2,P1} = 11,560.56 \text{ lbs}$  of digester slurry per day leaves the digester as effluent

$y_{3,P1} = 4,075.77 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously,

$y_{3,P1} = 2,703.84 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage,

$y_{1,P2} = 0.51 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas,

$y_{2,P2} = 0.51 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 0.22 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

---

Solution to 7 days of refilling the tank at 1.88 cfm  
with pure methane is :

$18,926.90 \text{ ft}^3$  or  $535.95 \text{ m}^3$

Compare 7 days of tank refilling  $535.95 \text{ m}^3$ , with the  
following MCFC gas holder tank sizes :

4hrsx5d	8hrsx5d	4hrsx7d	8hrsx7d
309.48 m <sup>3</sup> ,	618.95 m <sup>3</sup> ,	433.27 m <sup>3</sup>	and 866.53 m <sup>3</sup>

Also the onsite generator size , based on tailgas 2.83 cfm is :  
0.0071 MW

---

The OpTiGaS static model showed that the digester site and generator company with 80 cows and a 70 kW fuel cell system would require a 535.95 m<sup>3</sup> (18,926.90 ft<sup>3</sup>) system of gas holder tanks with a continuous refill rate of 1.88 cfm of pure methane for grid power export.

On the generic farm itself, 2.83 cfm of mixed tail gas could run a fuel cell that generated 7 kW of power continuously. The 535.95 m<sup>3</sup> gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 70 kW power to the spot market. However, it appears to be slightly undersized for 8 hrs/day x 5 days x 70 kW to the spot market. The flow chart in Figure 5.28 shows the static network model for the generic80 farm.

The power dispatch to the spot market using the 70 kW system connected to the 535.95 m<sup>3</sup> gas holder storage was simulated using the OpTiGaS dynamic model. The data set was again derived from NYISO in July 2010 and used specifically as a training set to see the response to reacting to July 2010's Day Ahead Marginal price data. As it turns out in Figure 5.29, the 70 kW for 8 hours/day on spot market days from the Genco would lead to under capacity problems with the gas holder starting on day 9 (before the 216th hour) of 31 days, which meant that the Genco fuel cells would be forced to shut down electricity dispatch when the gas holder reach critically low methane levels regardless of the dispatch commitment with NYISO. Consequently that Genco would incur a penalty for not dispatching

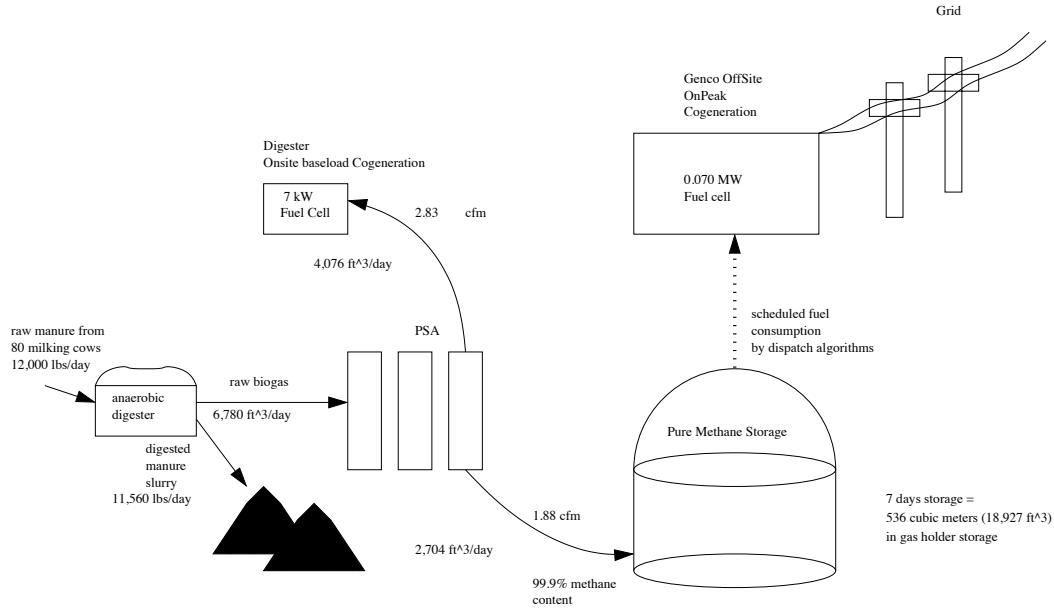
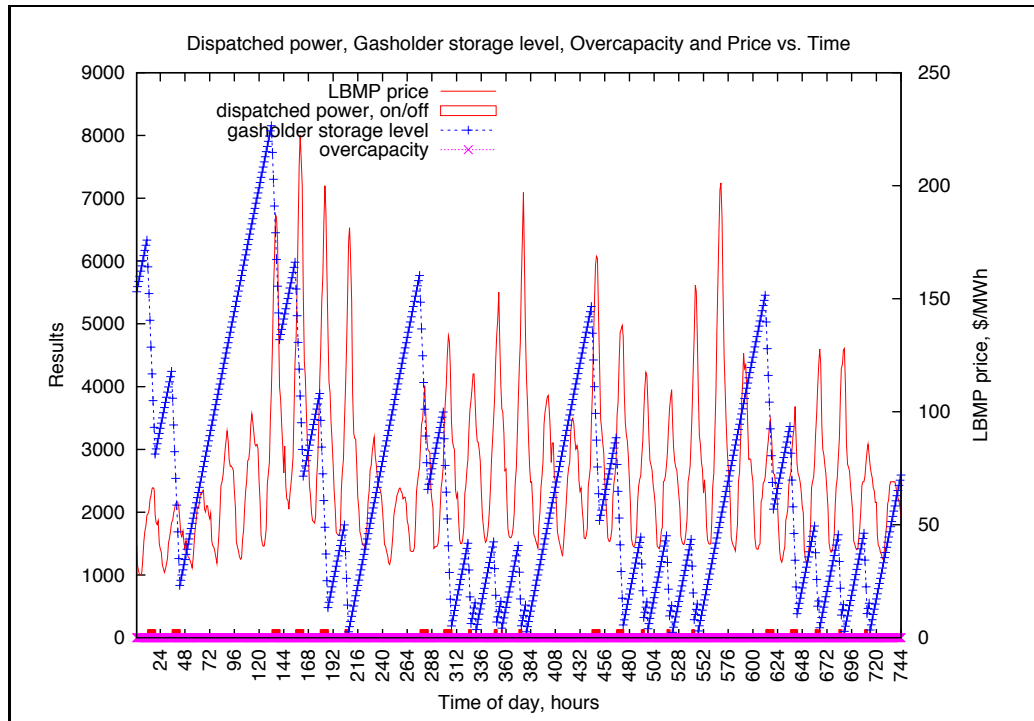


Figure 5.28: Resulting static model flow chart for the small generic farm with 80 milking cows

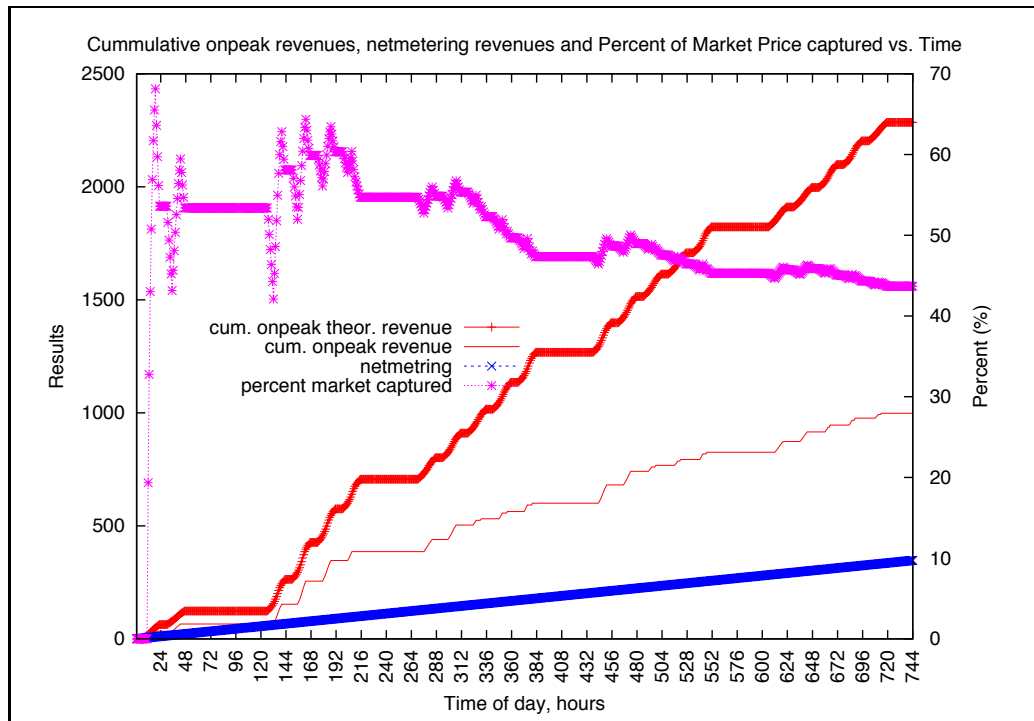
during committed hours. The revenue collected by the Genco using the 8hrs/spot market day shown in Figure 5.29 was calculated to be around \$998 for July 2010, representing 43.69% of the theoretical spot market revenue, \$2,285.

Alternatively dispatching 70 kW for 4 hours/day on spot market would eventually lead to overcapacity problems with the gas holder starting on Day 25 (before the 600th hour). The revenue collected by the Generic 80 cow Dairy and the Genco using the 4hrs/spot market day, shown in Figure 5.30, was calculated to be around \$753 for July 2010, representing 33% of the theoretical spot market revenue, \$2,285.

Reducing the herd size from 80 to 65 then 55 milking cows and running the fuel cell for 4hrs/day x 70 kW provided a remedy to methane consumption while maintaining gas storage levels that didn't cause overcapacity problems. The revenue collected by the Generic 55 cow farm using 4 hrs/day, shown in Figure 5.32 was calculated to be around \$753 for July 2010, representing 33% of the theoretical



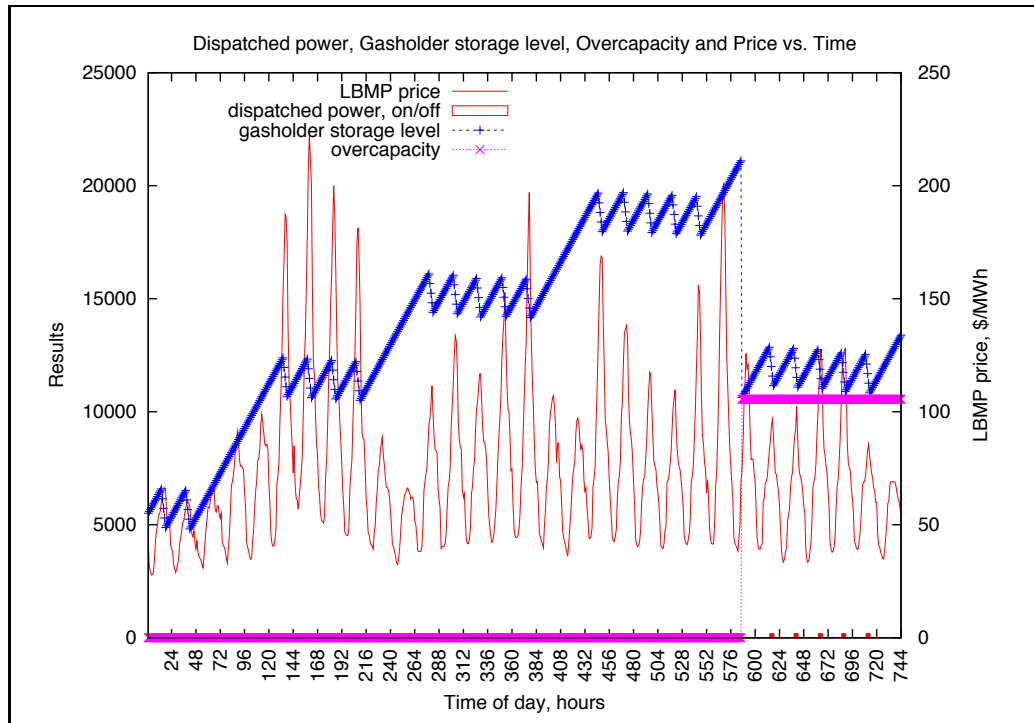
(a) Generic 80 cows, 70 kW and 8 hrs



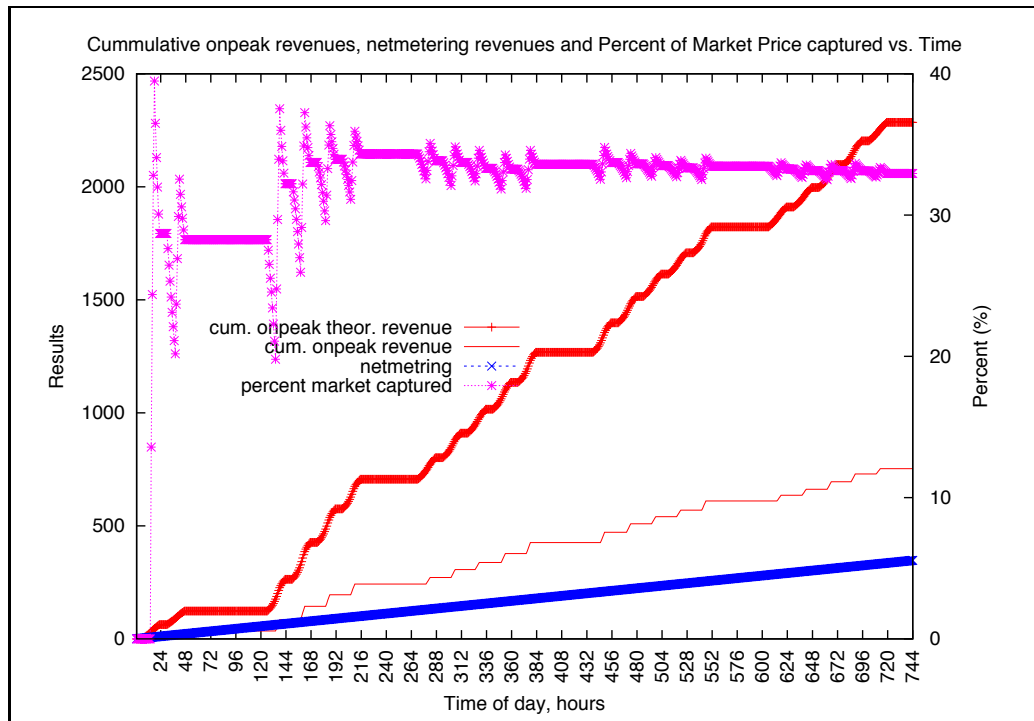
(b) Generic 80 cows, 70 kW, 8 hrs and revenue

Figure 5.29: Expected revenue at a Generic farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 80 cows, 70 kW and 8 hrs





(a) Generic 80 cows, 70 kW and 4 hrs



(b) Generic 80 cows, 70 kW, 4 hrs and revenue

Figure 5.30: Expected revenue at a Generic farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 80 cows, 70 kW and 4 hrs

spot market revenue, \$2,285. Not surprisingly, that is the same resulting revenue for when the generic 80 cows or generic 65 cow dairy farm digester and Genco dispatched 70kW of power to the grid. This is to be expected because the gas consumption to meet that fuel cell demand with 4hrs/spot market day is identical. Only the gas holder size and refill rate is different namely: 19,000 ft<sup>3</sup>, 15,400ft<sup>3</sup> and 13,100 ft<sup>3</sup> for the 80 cow, 65 cow and 55 cows generic dairy case studies in New York.

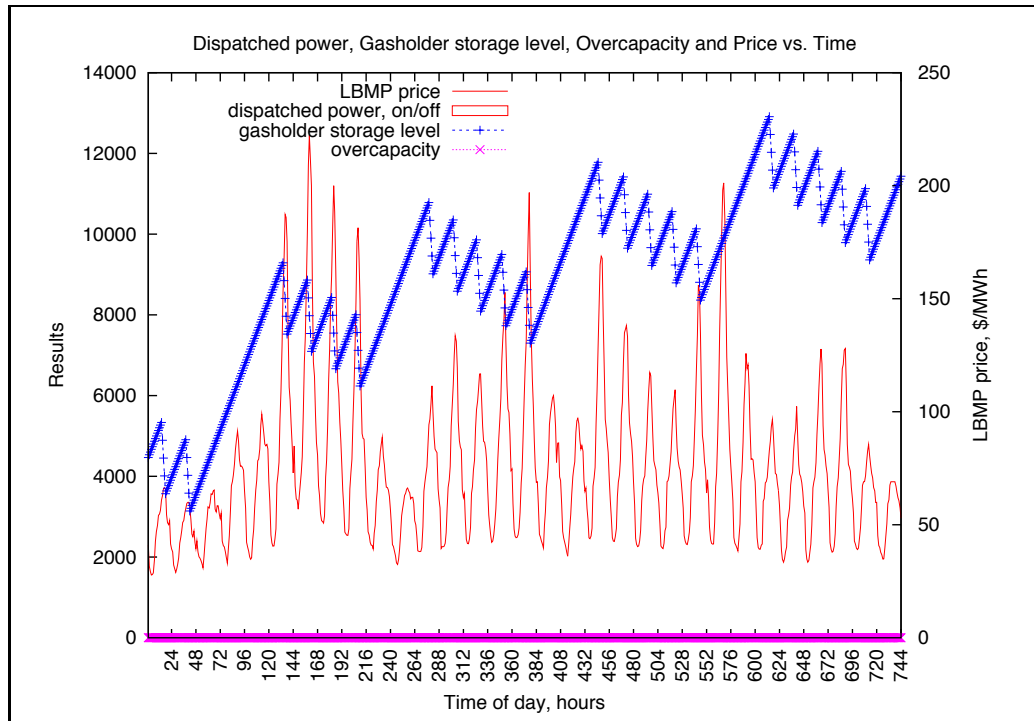
Because OptiGas is really intended to sell whole sale power, ie 1MW or higher to the NYISO wholesale market, one obvious arrangement would be to cluster more than fifteen farms of 55 cow farm size to sum to 1 MW of power:

$$15 \times 70 \text{ kW} = 1.05 \text{ MW}$$

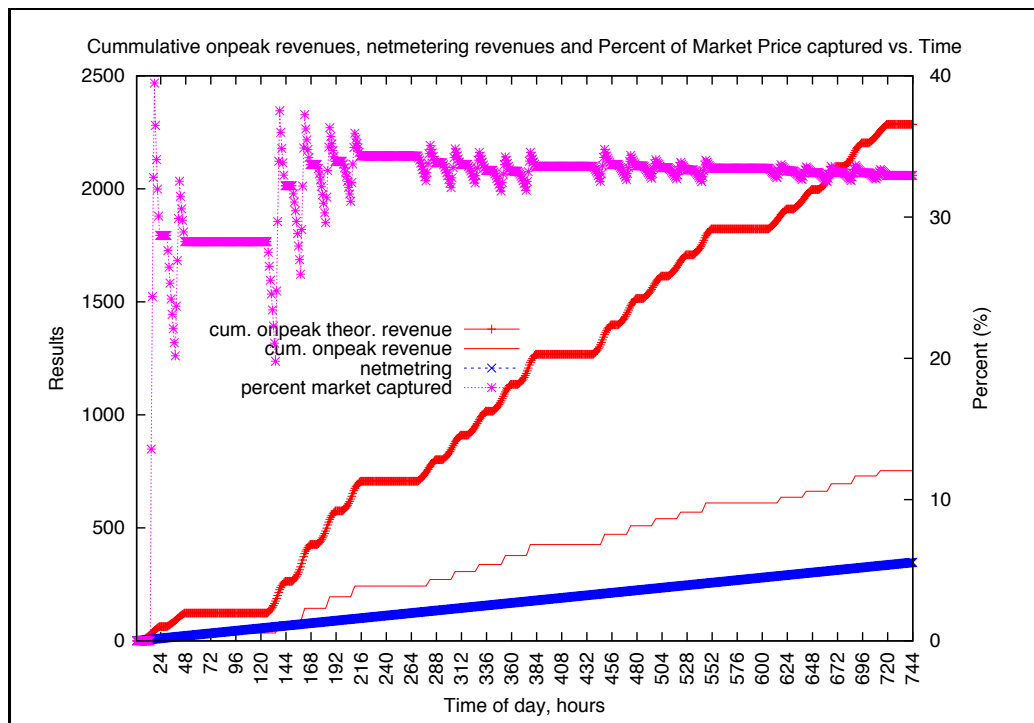
from one centralized Genco company to sell the the spot market grid just like in Figure 5.33.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system.

1. Biomass input = biogas from a cluster of 15 dairy farms with an average of 80 milking cows/farm
2. Gas holder size 8,040 m<sup>3</sup> for pure methane = four 2,000 m<sup>3</sup> gas holder tanks or two 6,000 m<sup>3</sup> gas holder tanks, but only required to ship the equivalent of 15 x 55 cows worth of pure methane to the Genco MCFC fuel cells.
3. Fuel cell size for onpeak generation from the cluster =1.2 MW (4 DFC300MA fuel cells) with the flexibility to throttle down to 1,000 kW
4. In July 2010 generate power for 4hrs/day per spot market day based on the OpTiGaS scheduled dispatching

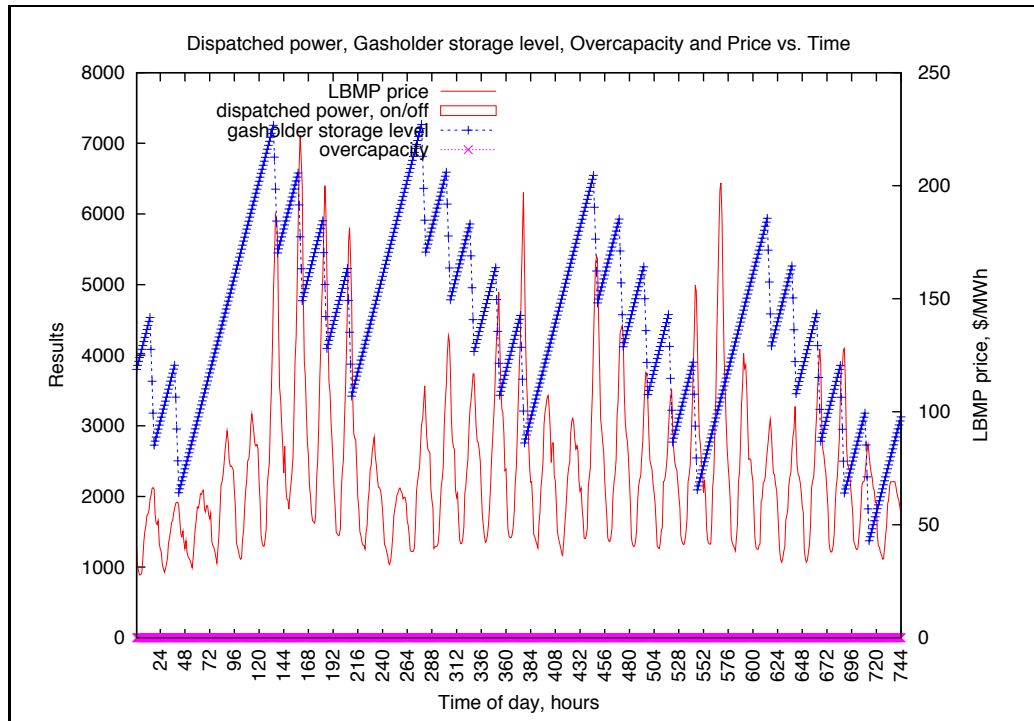


(a) Generic 65 cows, 70 kW and 4 hrs

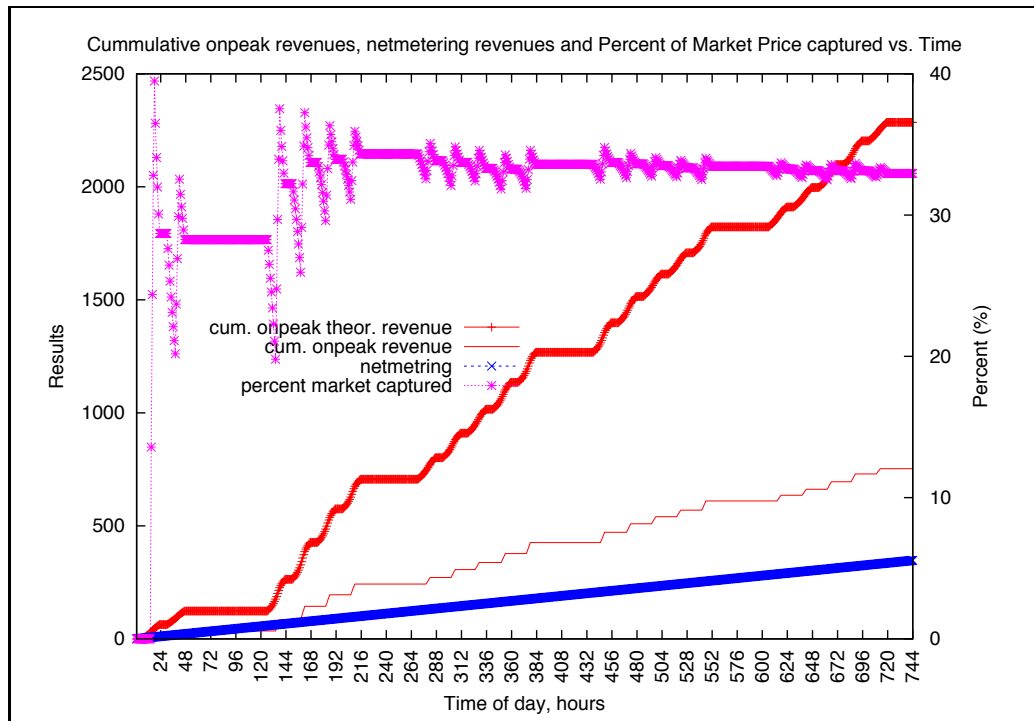


(b) Generic 65 cows, 70 kW, 4 hrs and revenue

Figure 5.31: Expected revenue at a Generic farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 65 cows, 70 kW and 4 hrs



(a) Generic 55 cows, 70 kW and 4 hrs



(b) Generic 55 cows, 70 kW, 4 hrs and revenue

Figure 5.32: Expected revenue at a Generic farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 55 cows, 70 kW and 4 hrs

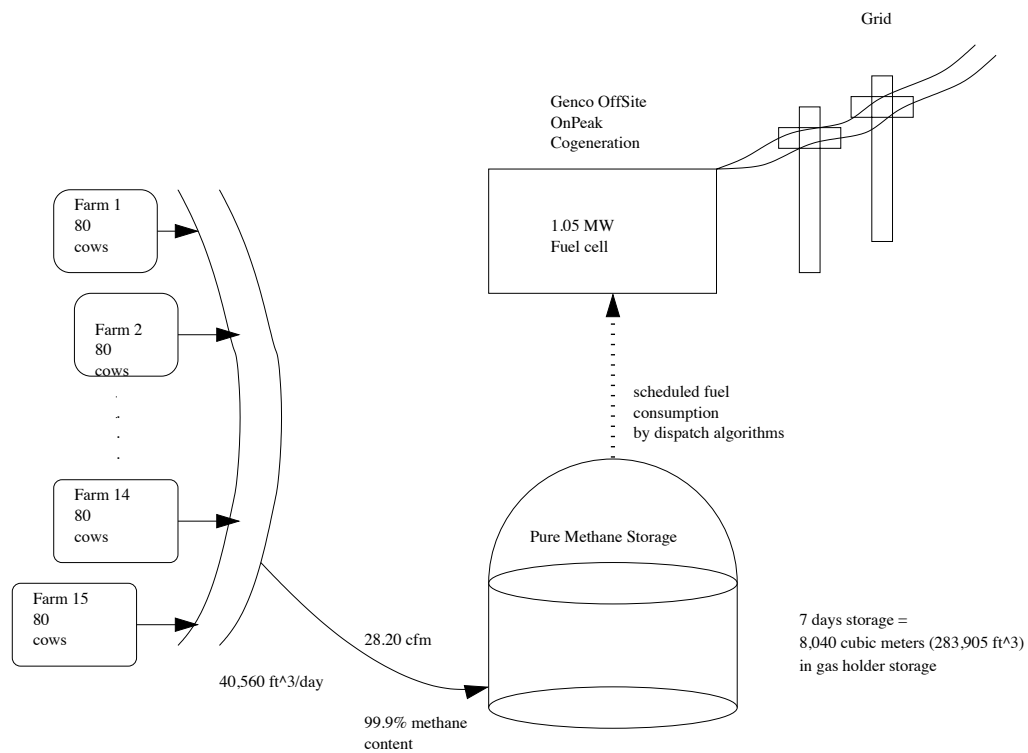


Figure 5.33: Resulting Static model flow chart for clustering of 15 farms having the same scale as the generic 55 cow farm and piping pure methane to one single Genco to sell onpeak power.

5. Fuel cell size for each of the 15 local onsite fuel cell generators = 7 kW (a tiny MCFC or solid oxide fuel cell from manufacturers TMI or Ceramic Fuel Cell) running on dilute methane in the tail gas mixed with pure methane with 42.7% methane content. This is assumed to be the minimum practical size for onsite power generation at a small farm to cover each farm's baseload needs and minimize purchasing power from the local utility grid.
6. Pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.
7. Sign a tolling agreement between the Genco and fifteen (15) small 80 cow dairy farm digester sites.
8. The farm digester site successfully fulfilling the NYISO Standard Interconnection Requirement document with local utility for net metering
9. The Genco successfully accepted to sell whole sale power to the NYISO spot market as a market participant
10. Internet downloading of spot market data to enable bids into the day ahead market and six day load forecast data
11. Natural gas pipeline as a backup in case of the rare situation of insufficient biogas in the gas holder

## CHAPTER 6

### CASE STUDIES AND RESULTS FOR APPLICATION OF OPTIGAS

Four digester sites were used as case studies for applying the OpTiGaS System:

1. Patterson Farms
2. AA Dairy
3. Vintage Farm cluster
4. Sunnyside Farm

Each represents a different scale of digester site, small to large, as well as different types of digestible feedstock and scale of fuel cell system. The intent of the case studies is to investigate the potential for converting digester sites into on peak dispatchable Gencos with methane pipelines and appropriately sized gas holders. The 4 farms were also picked because they all do net metering. That means their energy production and consumption data is available for comparison and analysis.

#### **6.1 Patterson Farm Digester Site: A Large Dairy Example**

Patterson Farm has 1,700 milking cows with an operational anaerobic digester and originally installed a 180kW generator for net metering. More than half of the biogas produced was in excess of the generator's required biogas flow rate and had to be flared for carbon credits. Subsequently a second generator, 225 kW, was installed in 2009, making a total of 405 kW of power generation from Patterson Farm. With the two generators, Patterson Farms currently participates in two NYSERDA distributed generation programs: System 1 (180 kW) for selling power to a grid tied net metering program and System 2 (225 kW) for selling excess power

to a DSASP demand side ancillary services program after supplying onsite power to Patterson Farm. In the event of a power cut, System 1 shuts off completely and the farm disconnects from the grid, while System 2 instantaneously provides onsite power in island mode.

According to NYSERDA fact sheets<sup>91</sup> the equivalent of 250,000 to 270,000 lbs of manure is collected daily from the 1,700 milking cows. When the excess biogas (in column 4) was assumed not flared but added back, then total biogas from digester (column 4 + column 5) would be 94,193cf +74,789 cf =168,982 ft<sup>3</sup>.

In the first row, Total heat recovery = total useful heat recovery (MBtu) + total unused heat recovery(MBtu)= 15,987+10,968= 26,965 MBtu. The percent useful heat recovery (column 8) = useful /(useful+unuseful)

$$15,987/(15,987+10,968)= 15,987/26,965= 59\%$$

Total generator gas used = 941.93 ccf = 94,193 cf. Assuming 1cf of pure methane =1,000 Btu, then total available btu before combustion in the generator = 94,193,000 Btu or 94,193 Mbtu or 94.19 MMBtu. Assuming 60% methane in the biogas, then MBtu is from biogas, not pure methane, therefore = 94,193 \* 60%=56,516 Mbtu.

Breaking down the digester biogas path/day into steps we get:

168,982 cf → 94,193 cf (to generator) + 74,789 cf (to flare)

→ 44,873 MMBtu (to flare): 56,516 MMBtu (to generator),

→ 101,389 MMBtu (both flare and generator)

→ 44,873 MMBtu: 19,781 MMBtu: 15,987 MMBtu: 10,968 MMBtu: 9,770 MMBtu

total energy from biogas (100%) = flare(44.26%): electricity (19.51%): useful heat recovery(15.76) : unused heat recovery (10.81%) : not recoverable energy (9.64%)

total energy from digester biogas (100%)

→ useful (19,781+15,987=35,768 Mbtu=35.27%): not used(64.72%).



Therefore, in one day digester biogas becomes 35% useful as cogen while 65% is not used.

All evidence pointed to the flare needing to be replaced with a boiler, dryer or additional power generation unit to use all that combustion productively. The flared excess should be stored (at least the methane part of it) temporarily for high energy demand times of the day instead of continuously wasting it. That's the reason why a second generator was installed at Patterson Farms in 2009 with a size of 225 W.<sup>92</sup>

To qualify as a Genco for the wholesale electricity market, Pattersen farm needs at least, a 1 MW generator. Thus for this analysis, I propose a 1.4 MW molten carbonate fuel cell generator system with the flexibility to trottle down to 1 MW.

With the known inputs of generator size and quantity of manure available, the OpTiGaS static model, developed in Chapter 4, can now be used to solve for gas holder size and gas refill rate. Mathematically we solve the  $A \cdot x = b$  shown below where the technology coefficients matrix  $A$ , multiplied by a vector of flow variables,  $x$ , is equal to the vector of known input-output quantities,  $b$  (255,000 tons of manure from 1,700 cows and 1.4 MW fuel cell).

$$\begin{bmatrix} \frac{1}{k_{(1,P1)}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{k_{(2,P1)}} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{1}{k_{(3,P1)}} & 0 & 0 & 0 & 0 \\ -1 & 0 & 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & -1 & 0 \\ 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(1,P3)}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{k_{(2,P3)}} \end{bmatrix} \cdot \begin{bmatrix} y_{1,P1} \\ y_{2,P1} \\ y_{3,P1} \\ y_{1,P2} \\ y_{2,P2} \\ y_{1,P3} \\ y_{2,P3} \end{bmatrix} = \begin{bmatrix} y_{0,P1} \\ y_{0,P1} \\ y_{0,P1} \\ 0 \\ 0 \\ y_{0,P3} \\ y_{0,P3} \end{bmatrix} \quad (6.1)$$

Determinant of A = 0.59845619

Stimulus variables input vector , b=

255,000.00

255,000.00

255,000.00

0.00

0.00

1.40

1.40

Solution output vector , x=

57,456.67

245,661.97

86,610.01

57,456.67

10.16

10.16

4.37

---

---

The interpretation of vector x is:

$y_{1,P1} = 57,456.67 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA;

$y_{2,P1} = 245,661.97$  lbs of digester slurry per day leaves the digester as effluent;

$y_{3,P1} = 86,610.01 \text{ ft}^3$  of mixed tail gas per day to run the onsite fuel cell;

$y_{3,P1} = 57,456.67 \text{ ft}^3$  of pure methane per day used to continuously refill the gas holder storage;

$y_{1,P2} = 10.16 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas;

$y_{2,P2} = 10.16 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 4.37$  MMBtu/hr of recoverable heat per dispatch period that is available from the cogenerated electricity.

In addition, the model calculates a pure methane refill rate of 39.9 cubic feet per minute and total methane production per week (7 days) of 402,197 cubic feet. The following snippet at the end of the model's output shows the gas holder sizes required for different dispatch schedules. It also shows the maximum size of an MCFC fuel cell that can run off of the tailgas produced.

---

---

```

...
Solution to 7 days of refilling the tank at 39.90 cfm
with pure methane is:

402,196.71 ft^3 or 11,388.93 m^3

Compare 7 days of tank refilling 11388.93 m^3, with the
following MCFC gas holder tank sizes:

5dx4hrs      5dx8hrs      7dx4hrs      7dx8hrs
6,189.51 m^3, 12,379.02 m^3, 8,665.31 m^3 and 17,330.62 m^3

Also the onsite generator size, based on tailgas 60.15 cfm is:
0.1502 MW

```

---

---

The OpTiGaS static model showed that the digester site with 1,700 cows and a 1.4 MW fuel cell system would require gas holder tanks with a volume of at least 11,400 m<sup>3</sup> (403,000 ft<sup>3</sup>) and a continuous gas refill rate of 39.9 cfm of pure methane for grid power export. On the farm itself, 60.15 cfm of mixed tail gas could run a fuel cell that generated 150 kW of power continuously. The 11,400 m<sup>3</sup> (403,000

ft<sup>3</sup>) gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 1.4 MW power to the spot market. However, it appears to be slightly undersized for 8 hrs/day x 5 days x 1.4 MW to the spot market.

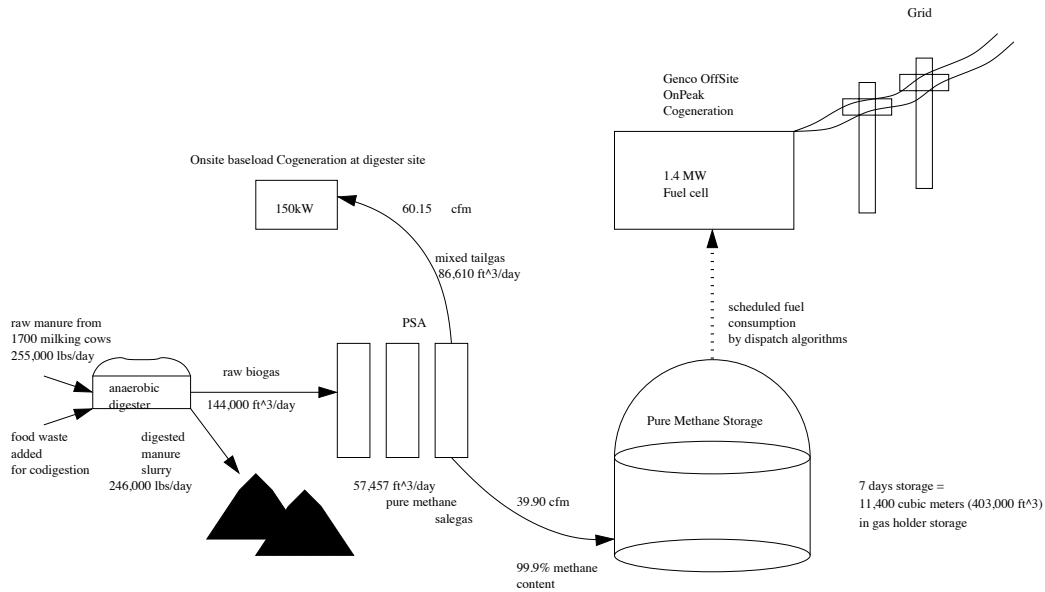


Figure 6.1: Resulting static model flow chart for Patterson Farm

The static model of Patterson Farm system is illustrated by Figure 6.1. With the results of this model, the OpTiGaS dynamic model was used to determine how the Patterson Farm system would perform well using historic time series data for 2010.

### 6.1.1 Applying OpTiGaS Dynamic Model to Patterson Farm

#### Digester Site

The power dispatch to the spot market using the 1.4 MW system connected to the 11,400 m<sup>3</sup> gas holder storage was simulated using the dynamic model. The data set was from NYISO in July 2010 and specifically the Day Ahead Marginal price data. The model was run first for 1.4 MW dispatch for 4 hours/day on spot

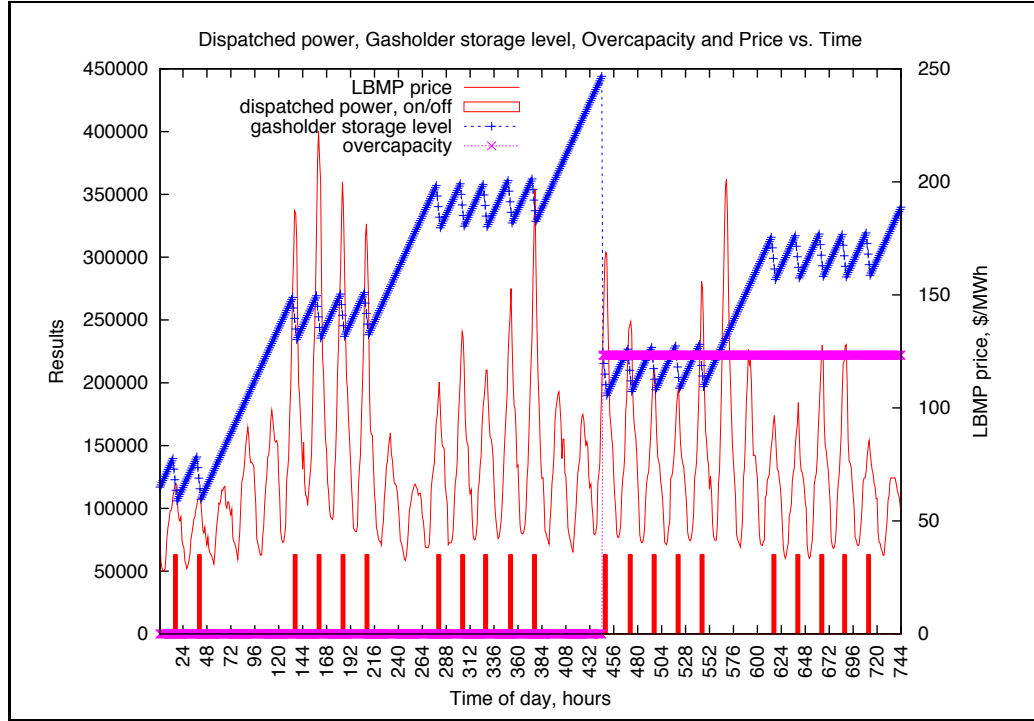
market days. The results, presented in Figure 6.2, show a major overcapacity problem beginning about halfway into the month. This is due to the fact that the fuel cell consumption of methane for power generation is slower than the methane refilling rate.

Running the fuel cell for 8 hrs/day with the fuel cell throttled down to 1 MW provided a remedy to balancing methane consumption with gas storage levels (Figure 6.3). The revenue collected by Patterson Farms in this scenario was calculated to be \$19,000 for July 2010, representing 59% of the maximum theoretical spot market revenue of \$32,000 for the given period. The best outcome was for 8 hrs/-day with the fuel cell at 1.1 MW generation capacity (Figure 6.4). In this scenario, the revenue was \$21,000 in onpeak revenue compared to the theoretical maximum of \$35,000. That was 58% collected. In contrast the digester site would normally make \$4,000 from net metering over 24 hours/day, 7 days/week, with an engine generator set of the same capacity.

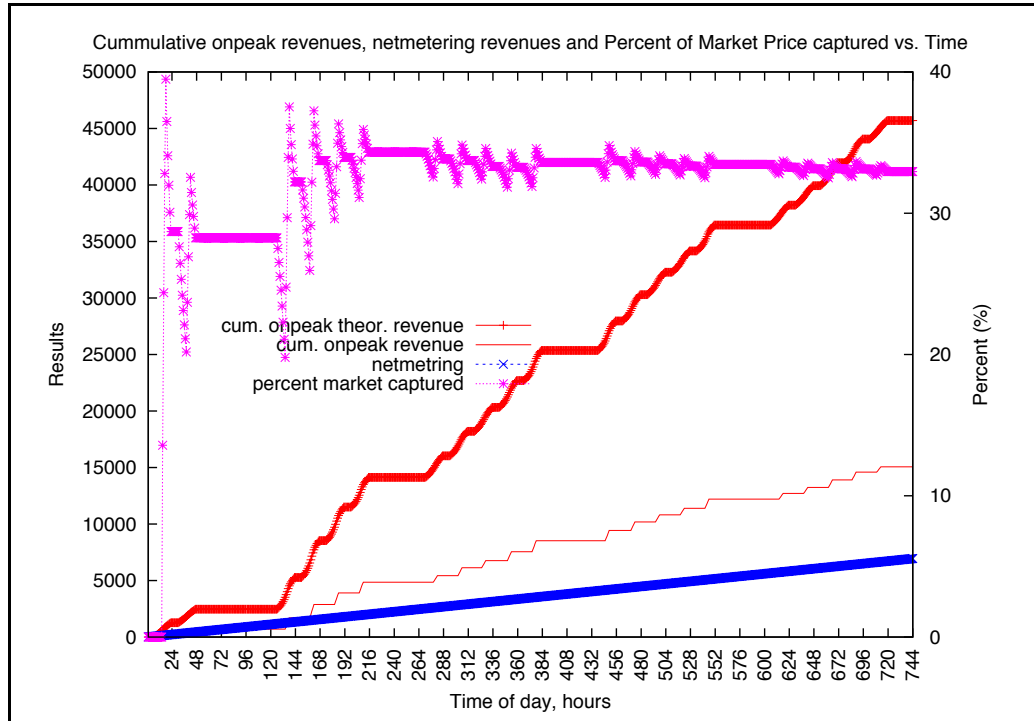
The model was run with other generator sizes as well. An alternate solution that emerged to the overcapacity problem in the 4-hour dispatch schedule was to use a 2 MW fuel cell generator system instead. This system would make the same revenue as .... ,. However, as a percentage of the theoretical revenue possible with the larger generator, the revenue is 32.95% over the full 31 day period.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system.

1. Biomass input = biogas from a minimum of 1,700 milking cows.
2. Gas holder size with volume of 11,400 m<sup>3</sup> for pure methane = six 2,000 m<sup>3</sup> gas holder tanks or two 6,000 m<sup>3</sup> gas holder tanks.
3. Fuel cell size for onpeak generation = 1.4 MW with the flexibility to throttle

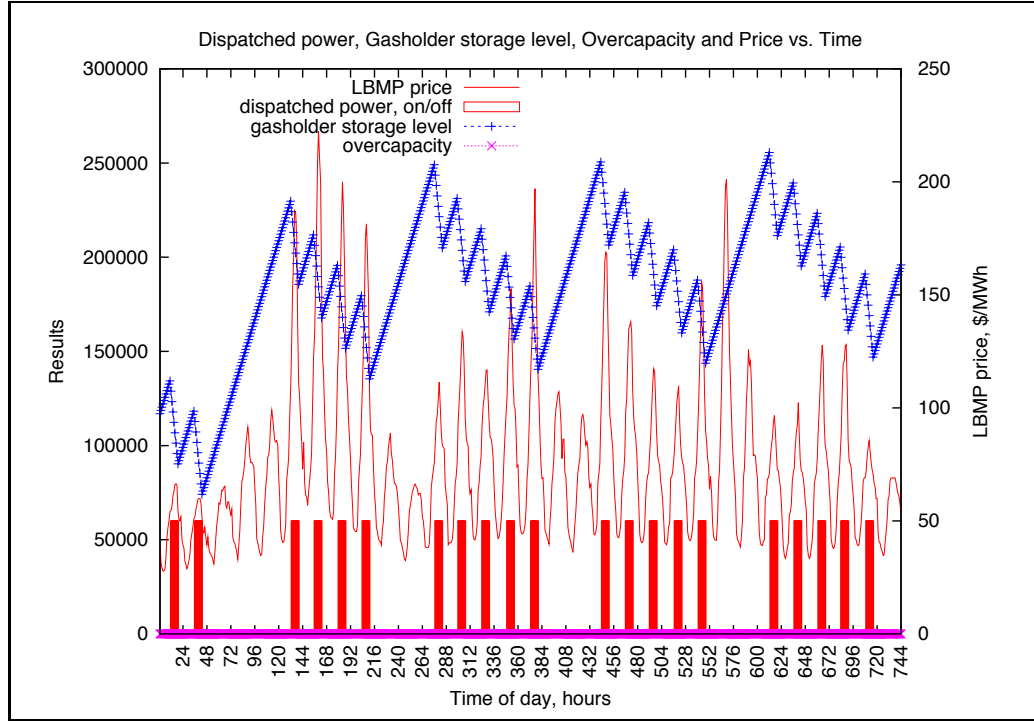


(a) Patterson 1700 cows, 1400 kW and 4 hrs

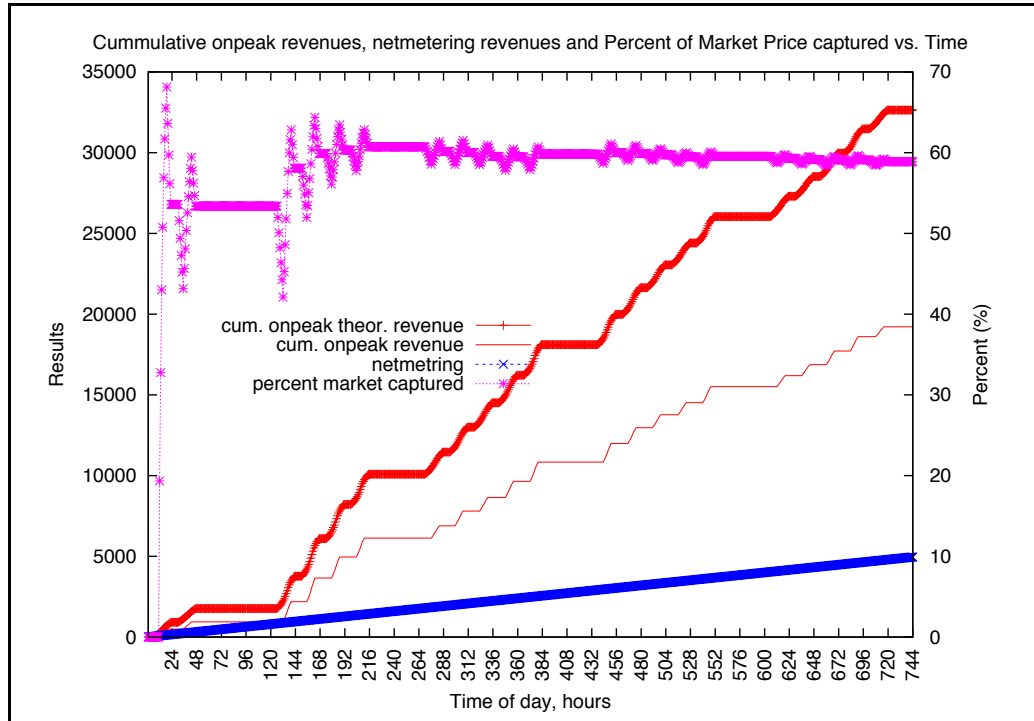


(b) Patterson 1700 cows, 1400 kW, 4 hrs and revenue

Figure 6.2: Dispatched power and expected revenue at Patterson Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 1,700 cows, a 1.4 MW generator and 4 hours/day generation.

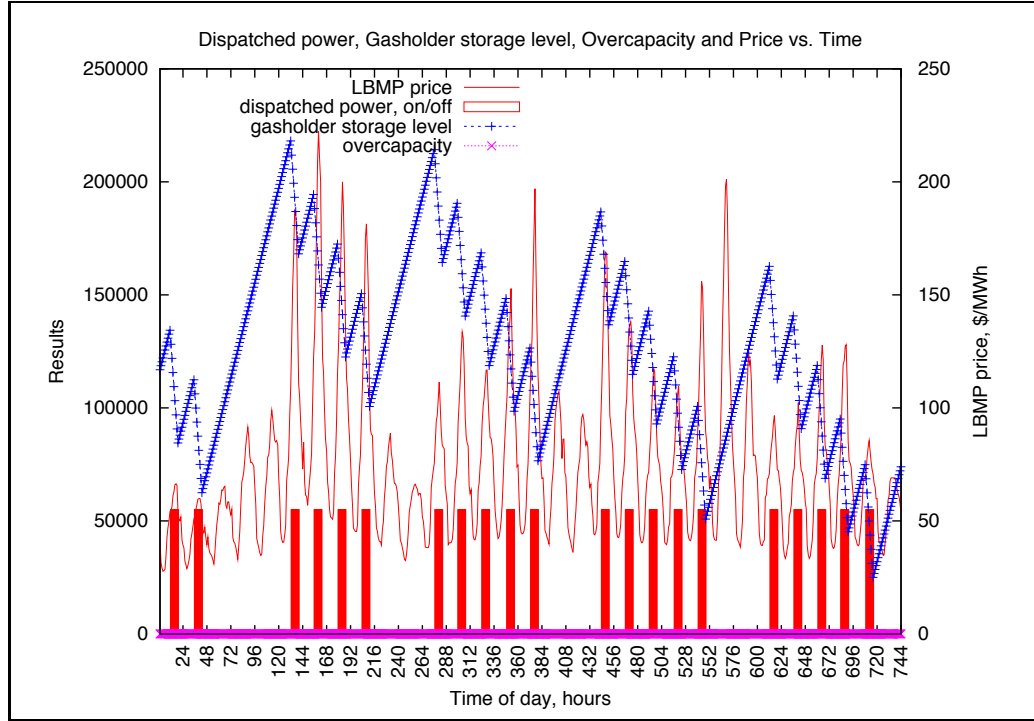


(a) Patterson 1700 cows, 1000 kW, and 8 hrs

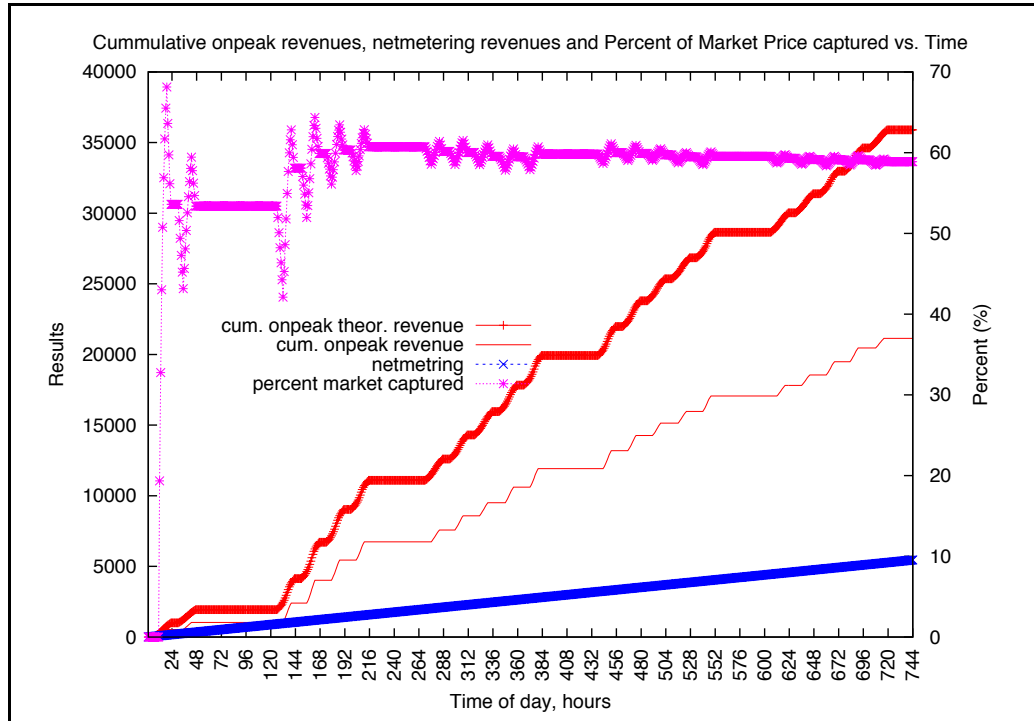


(b) Patterson 1700 cows, 1000 kW and 8 hrs revenue

Figure 6.3: Dispatched power and expected revenue at Patterson Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 1700 cows, a 1.0 MW generator and 8 hours/day generation.



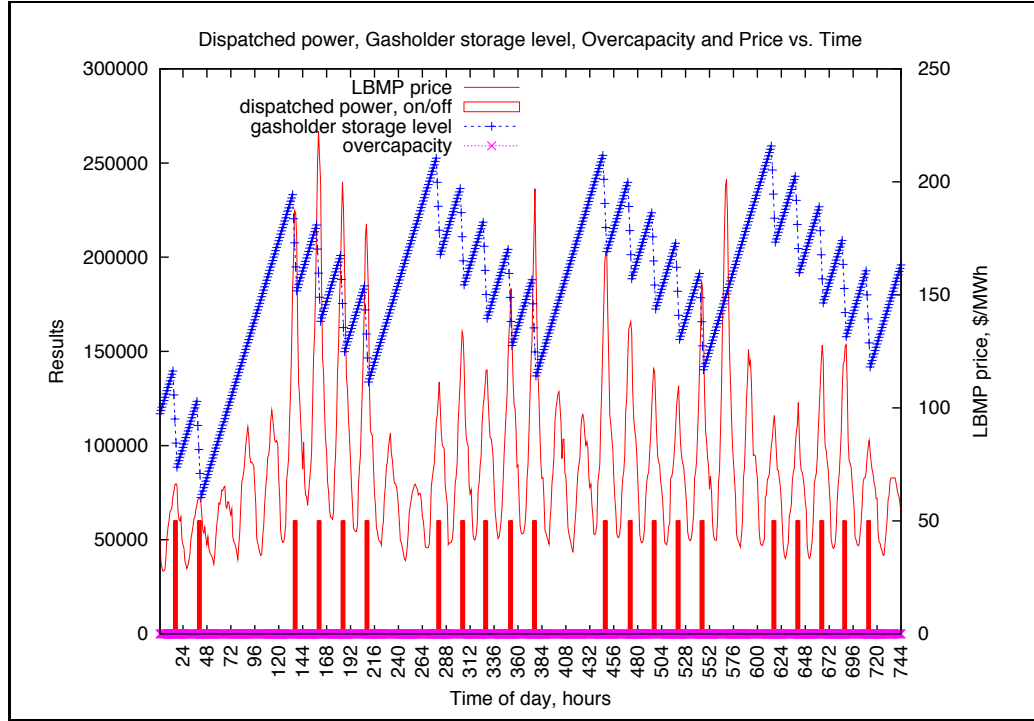
(a) Patterson 1,700 cows, 1,100 kW and 8 hrs



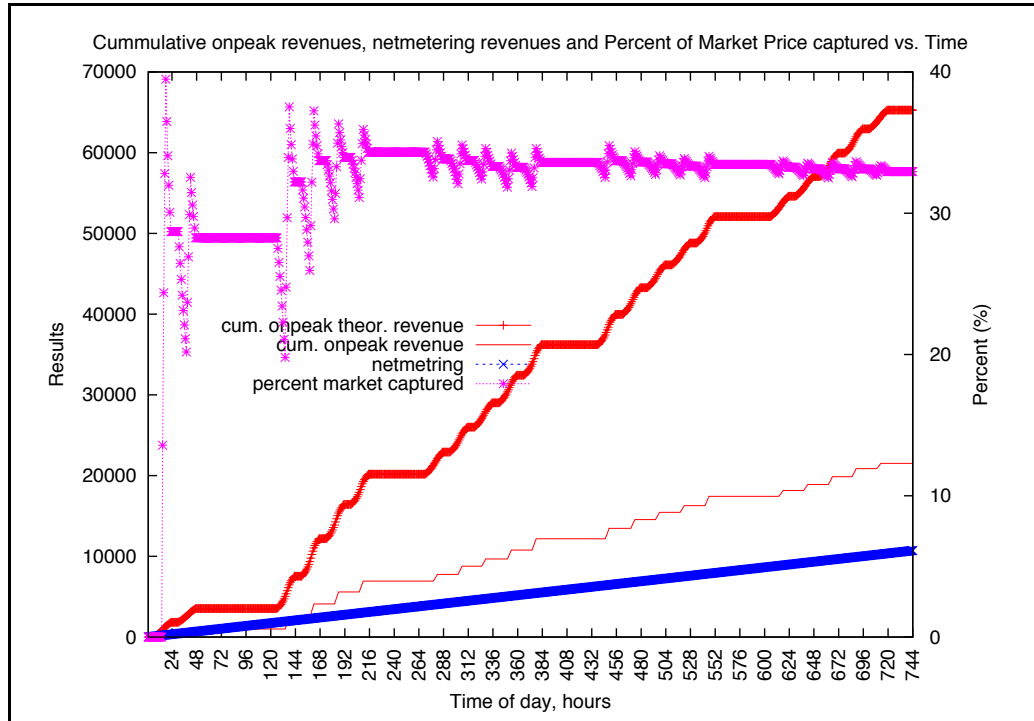
(b) Patterson 1,700 cows, 1,100 kW, 8 hrs and revenue

Figure 6.4: Dispatched power and expected revenue at Patterson Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 1700 cows, a 1.1 MW generator and 8 hours/day generation.





(a) Patterson 1,700 cows, 2,000 kW and 4 hrs



(b) Patterson 1,700 cows, 2,000 kW, 4 hrs and revenue

Figure 6.5: Dispatched power and expected revenue at Patterson Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 1700 cows, a 2.0 MW generator and 4 hours/day generation.

down to 1.1 MW or 1 MW. (FuelCell Energy Inc. manufactures the DFC-1500 which can output 1.0 to 1.4 MW of power.)

4. Fuel cell size for local onsite generation = 150 kW = a 300 kW MCFC running on dilute methane in the tail gas.
5. Pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell.
6. The farm successfully fulfilling the standard interconnection requirement document with the local utility.

## **6.2 AA Dairy Digester Site: A Mid-size Dairy Farm**

AA Dairy is a medium size farm by New York State standards, with approximately 600 milking cows. It also has the honour of having one of the longest operational digesters in the state. Their digester has been in operation since 1998. The digester was originally designed for 1,000 cows. Thus, the site's current 50,000 ft<sup>3</sup> biogas production and 70 kW electricity generation system is operating at half of the original design capacity (100,000ft<sup>3</sup>/day, and 130 kW.) Excess power is sold back to the grid after the farm gets its first share. This is a sensible approach because AA Dairy saves at the retail price level of about \$0.145/kWh by using its own energy first, compared to the \$0.02 to \$0.04 it would receive from straight net metering.

The OpTiGaS static model was used to simulate the projected improvement and restructuring of AA Dairy dispatched electricity set-up. The model was run several times with the manure input from 600 cows and a range of fuel cell generator sizes from 1.0 to 0.4 mW in 0.05 MW increments. A generator size of 0.45 MW was selected for the proposed system. This was the maximum value for which a

7-day dispatch schedule was possible. The various methane production statistics in the flow variables vector (x) obtained for 600 cows and 0.45 MW are shown in the listing below.

---

---

```
Determinant of A = 0.59845619
Stimulus variables input vector , b=
    90000.00
    90000.00
    90000.00
     0.00
     0.00
     0.45
     0.45
```

```
Solution output vector , x=
    20278.83
    86704.22
    30568.24
    20278.83
     3.27
     3.27
     1.40
```

---

---

The interpretation of vector x is:

$y_{1,P1} = 20278.83 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA;

$y_{2,P1} = 86704.22 \text{ lbs}$  of digester slurry per day leaves the digester as effluent;

$y_{3,P1} = 30568.24 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously;

$y_{3,P1} = 20278.83 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage;  
 $y_{1,P2} = 3.27 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas;

$y_{2,P2} = 3.27 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 1.40 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

In addition, the model calculates a pure methane refill rate of 14.08 cubic feet per minute and total methane production per week (7 days) of 141,952 cubic feet. The following snippet at the end of the model's output shows the gas holder sizes required for different dispatch schedules. It also shows the maximum size of an MCFC fuel cell that can run off of the tailgas produced.

---

---

Solution to 7 days of refilling the tank at 14.08 cfm  
 with pure methane is:

141,951.78  $\text{ft}^3$  or 4,019.62  $\text{m}^3$

Compare 7 days of tank refilling 4019.62  $\text{m}^3$ , with the following MCFC gas holder tank sizes:

5dx4hrs	5dx8hrs	7dx4hrs	7dx8hrs
1,989.48 $\text{m}^3$ ,	3,978.97 $\text{m}^3$ ,	2,785.28 $\text{m}^3$	and 5,570.56 $\text{m}^3$

Also the onsite generator size, based on tailgas 21.23 cfm is:  
 0.0530 MW

The OpTiGaS static model showed that the digester site with 600 cows and 0.45 MW fuel cell system would require a 4,020 m<sup>3</sup> (142,000 ft<sup>3</sup>) gas holder tanks with a continuous refill rate of 14.08 cfm of pure methane for grid power export. On the AA Dairy digester site itself, 21.23 cfm of mixed tail gas could run a fuel cell that generated 53 kW of power continuously. The 4,020 m<sup>3</sup> (142,000 ft<sup>3</sup>) gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 450 kW power and 8 hrs/day x 5 days x 450 kW power to the spot market. The flow chart in Figure 6.6 shows the static network model for the AADairy (including the separated solids composting facility and the separated liquid pond).

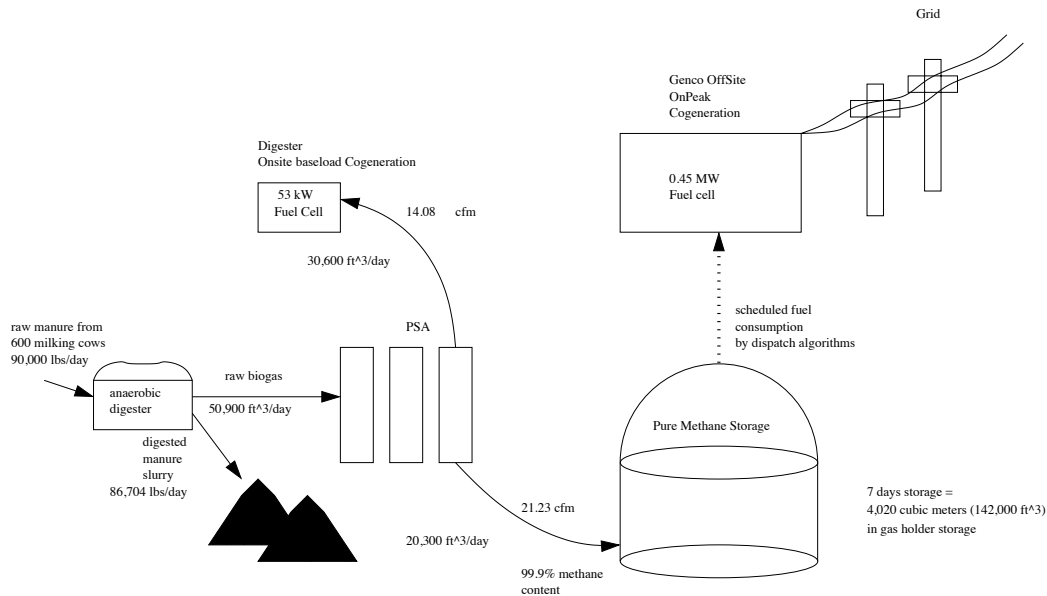


Figure 6.6: Resulting static model flow chart for AA Dairy case study

### 6.2.1 Applying OpTiGaS to AA Dairy Farm Digester Site

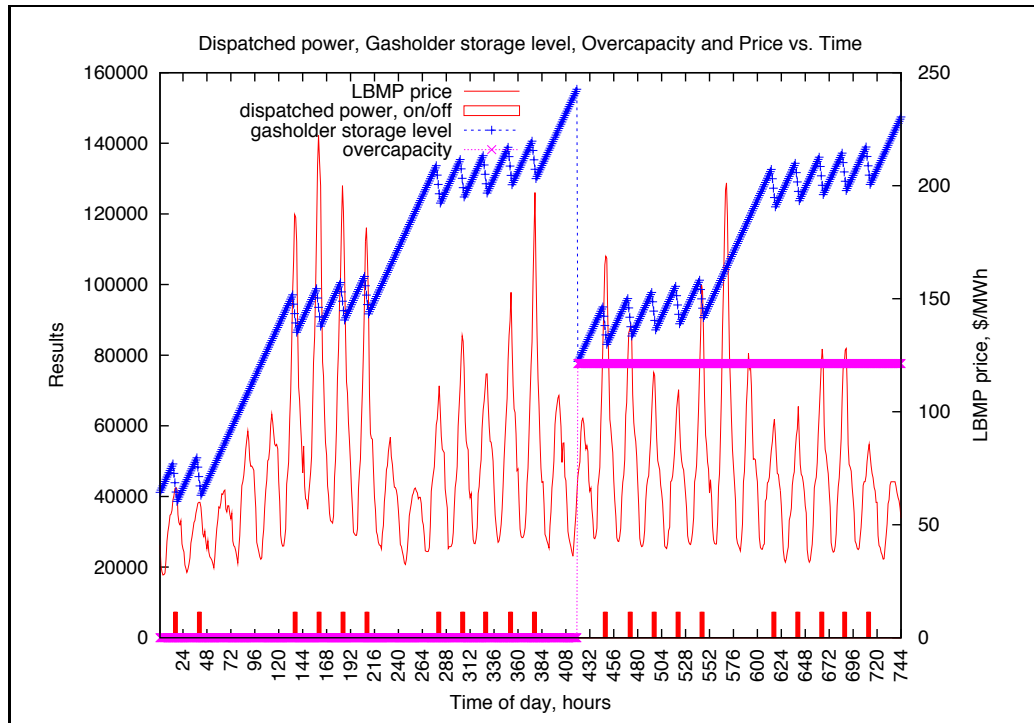
The power dispatch to the spot market using the 0.45 MW system connected to the 4,020 m<sup>3</sup> gas holder storage was simulated using the dynamic model. The same July 2010 data set from NYISO was used in this simulation of AA Dairy's case study.

The model was run first for 0.45 MW dispatch for 4 hours/day on spot market days. The results, presented in Figure 6.8, shows over-capacity problems in the second half of the month as the rate of methane refill is slower than the rate of consumption. The excess gas has to be flared or used in some other manner.

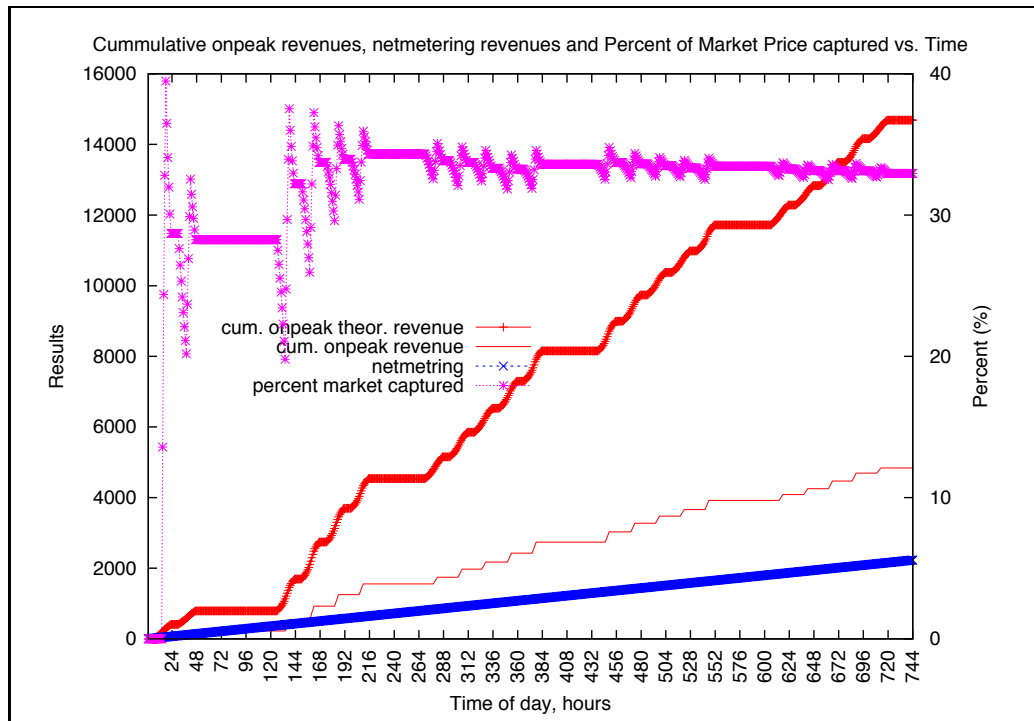
As shown in Figure 6.8, running the system for 8 hours/day on spot market days would lead to under capacity problems. This is because the methane consumption by the 0.45 W MCFC system outstrips the pace of the pure methane refilling, hence the Genco's inability to meet its scheduled dispatch generation on July 15 and eight subsequent days until the end of the month.

Keeping all other variables constant, the Genco for AA Dairy was reduced from 450 kW of onpeak dispatched power to 350 and 300 kW. The results of the simulations are shown in Figure 6.9 and 6.10. The best outcome seemed to have been for running the fuel cell for 8hrs/day x 350 kW which provided the remedy to methane consumption while maintaining gas storage levels that did not cause over or under capacity problems for the gas holder system. The revenue collected by AA Dairy in that case, shown in Figure 6.9 was calculated to be around \$6,800 for July 2010, representing 59% of the theoretical maximum spot market revenue of \$11,500 that the Genco could have collected from being on completely during the on peak periods of all spot market days in that month.

With only a maximum output of 0.45 MW system, AA Dairy is not large enough to qualify as a Genco in the wholesale electricity market. It would also be cost prohibitive to install a qualifying fuel cell system and the additional storage tanks required, only to sell electricity for just 2 to 3 days a week. An obvious solution would be to cluster more than two farms of AA Dairy's size or smaller. The static model for such a system is illustrated by Figure 6.11. Digesters from

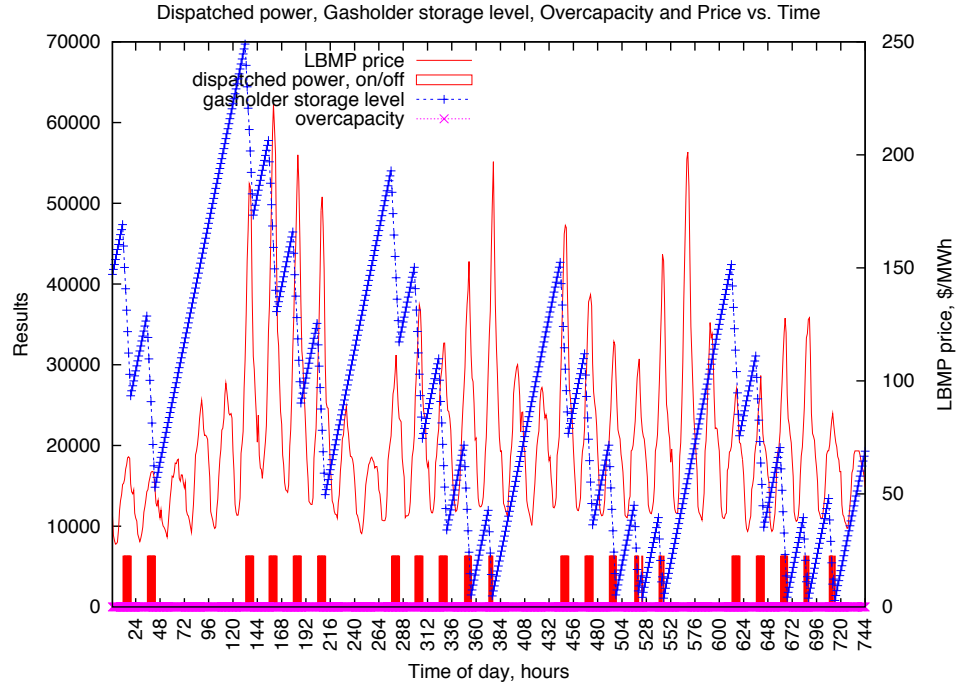


(a) AA Dairy 600 cows, 450 kW and 4 hrs

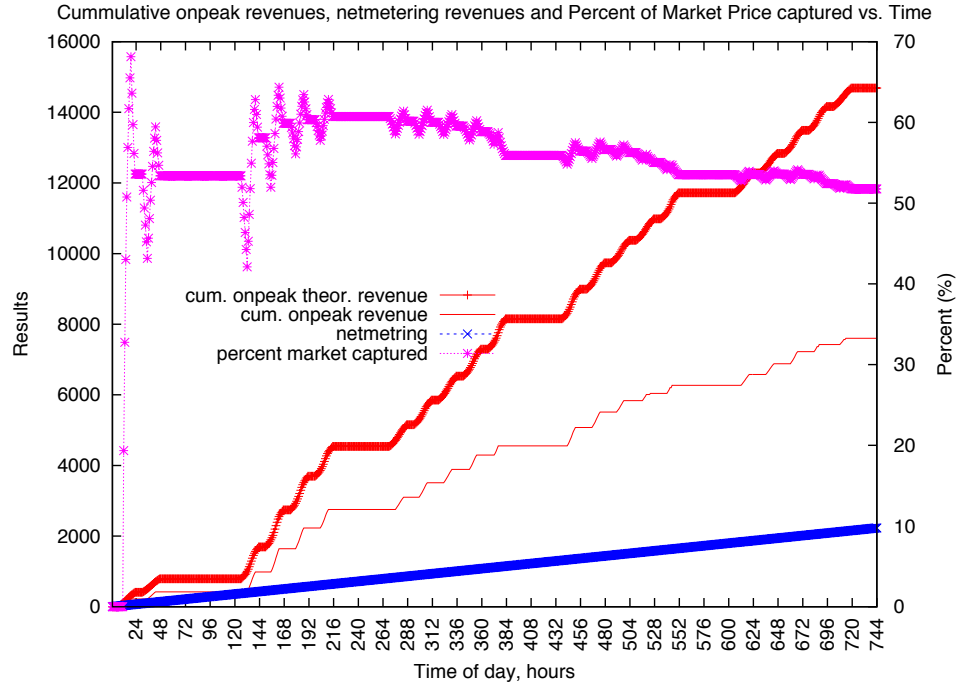


(b) AA Dairy 600 cows, 450 kW, 4 hrs and revenue

Figure 6.7: Expected revenue at AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 600 cows, 450 kW and 4 hrs



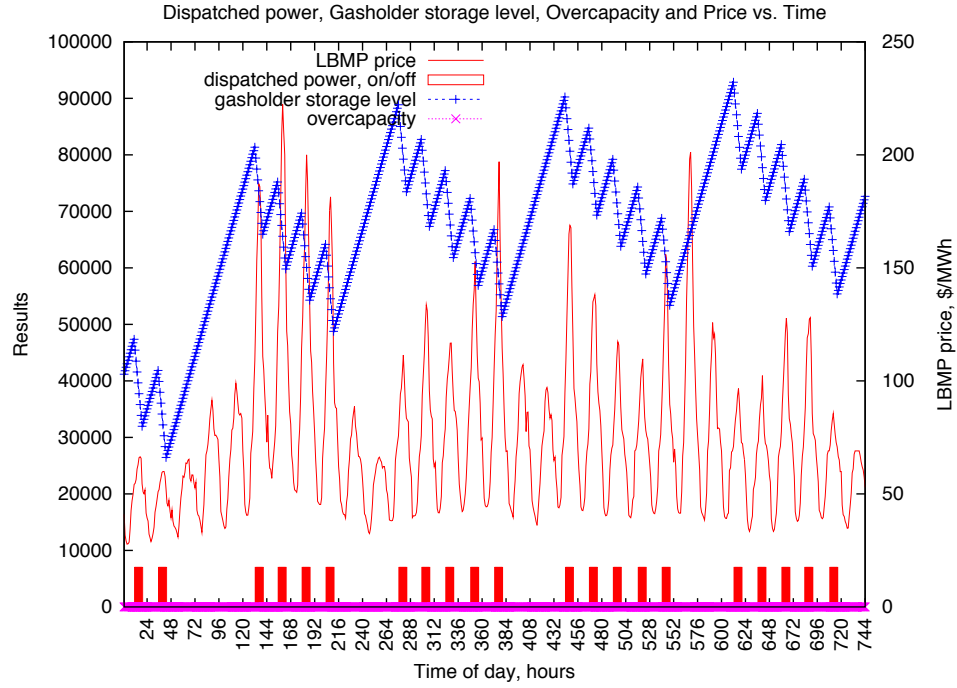
(a) Fuel storage and dispatch summary



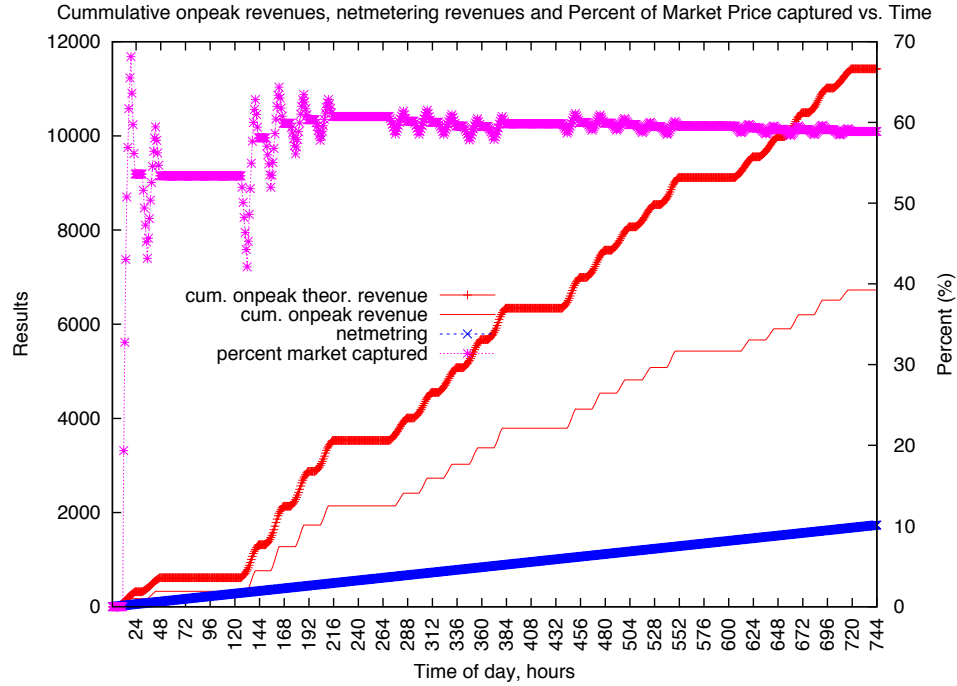
(b) Revenue summary

Figure 6.8: Dispatched power and expected revenue at AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 600 cows, a 0.45 MW generator and 8 hours/day generation.



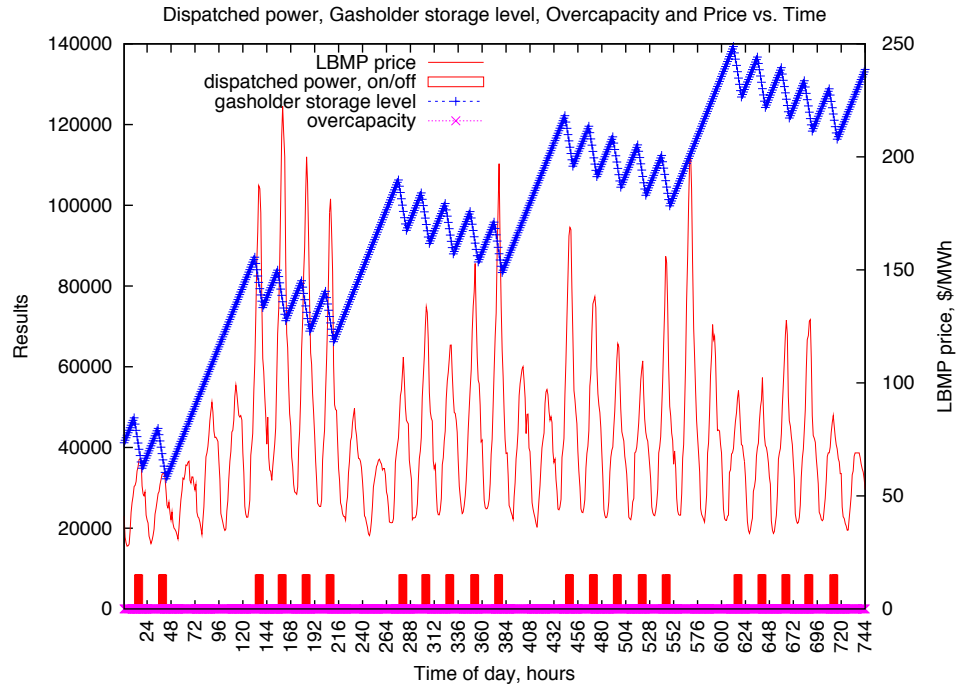


(a) Fuel storage and dispatch summary

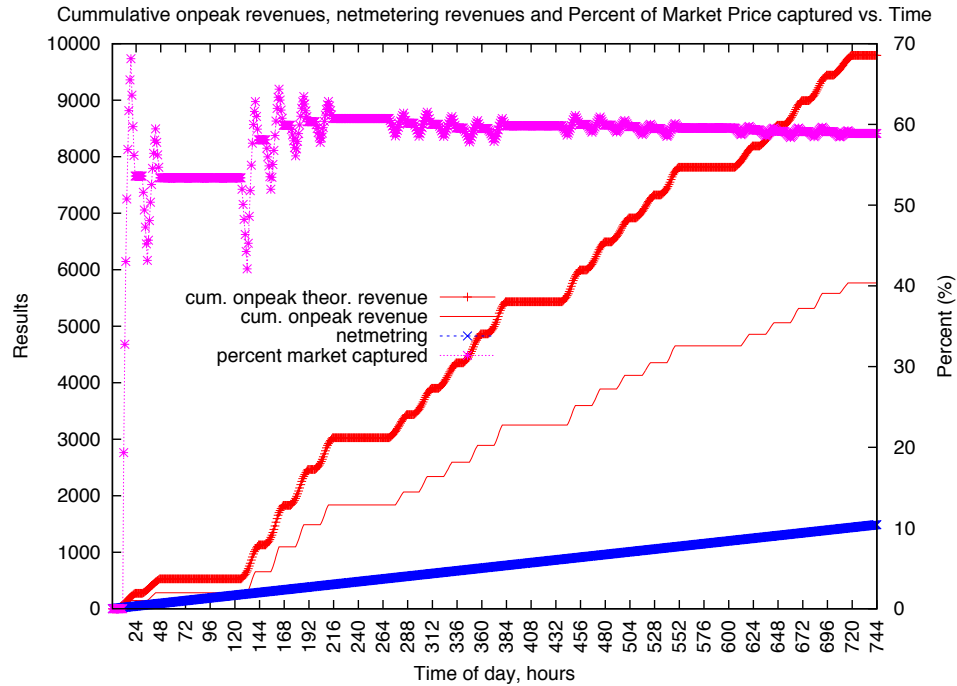


(b) Revenue summary

Figure 6.9: Dispatched power and expected revenue at AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 600 cows, a 0.35 MW generator and 8 hours/day generation.



(a) Fuel storage and dispatch summary



(b) Revenue summary

Figure 6.10: Dispatched power and expected revenue at AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the OpTiGas Model for 600 cows, a 0.30 MW generator and 8 hours/day generation.

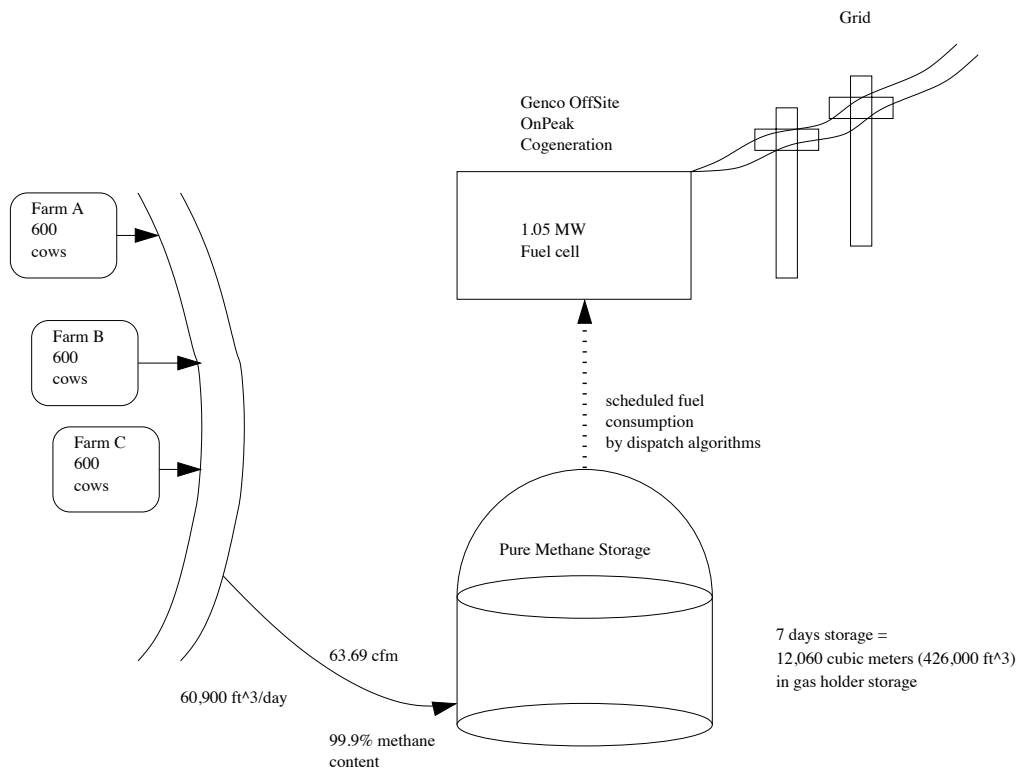


Figure 6.11: Resulting static model flow chart for clustering of three farms having the same scale as the AA Dairy case study and piping pure methane to one Genco to sell onpeak power.

the clustered farms, feed biogas or methane to a centralized Genco site that will qualify to sell whole sale power to the NYISO.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed for a medium size farm to participate in the wholesale market.

1. Biomass input = biogas from a cluster of 3 dairy farms with an average of 600 milking cows/farm
2. Gas holder size 12,060 m<sup>3</sup> for pure methane = six 2,000 m<sup>3</sup> gas holder tanks or two 6,000 m<sup>3</sup> gas holder tanks
3. Fuel cell size for onpeak generation from the cluster = 1.2 MW with the flexibility to throttle down to 1.1 or 1 MW.
4. For each 600 cow farm, fuel cell size for local onsite generation = 53 kW
5. Pipeline connecting the methane from the methane purifying PSA at the each of digester sites to gas holder storage and on peak fuel cell at the onpeak Genco.
6. Tolling agreements between the Genco and farms.
7. The Genco successfully fulfilling the standard interconnection requirement document with local utility.
8. The Genco successfully accepted to sell whole sale power to the NYISO spot market as a market participant.

## 6.2.2 Applying OpTiGaS to an Expanded AA Dairy Farm

### Digester Site

Since AA Dairy's digester and layout was originally designed for operating with up to 1,000 milking cows, simulations were also run for a megawatt scale fuel cell and 900 cows system. As in the 600 cow, 0.45 MW case, the first step was to determine the methane flow variables in the vector  $x$  using the known variables of manure available from 900 cows (135,00) and a 1.1 MW fuel cell.

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---

Determinant of  $A = 0.59845619$

Stimulus variables input vector,  $b =$

135,000.00

135,000.00

135,000.00

0.00

0.00

1.10

1.10

Solution output vector,  $x =$

30,418.24

130,056.34

45,852.36

30,418.24

7.99

7.99

3.43

---

---

The interpretation of vector  $x$  is:

$y_{1,P1} = 30,418.24 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA;

$y_{2,P1} = 130,056.34 \text{ lbs}$  of digester slurry per day leaves the digester as effluent;

$y_{3,P1} = 45,852.36 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously;

$y_{3,P1} = 30,418.24 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage;

$y_{1,P2} = 7.99 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas;

$y_{2,P2} = 7.99 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 3.43 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

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Solution to 7 days of refilling the tank at 21.12 cfm with pure methane is:

$$212,927.67 \text{ ft}^3 \text{ or } 6,029.43 \text{ m}^3$$

Compare 7 days of tank refilling 6,029.43  $\text{m}^3$ , with the following MCFC gas holder tank sizes:

5dx4hrs	5dx8hrs	7dx4hrs	7dx8hrs
4,863.19 $\text{m}^3$ ,	9,726.37 $\text{m}^3$ ,	6,808.46 $\text{m}^3$	and 13,616.92 $\text{m}^3$

Also the onsite generator size, based on tailgas 31.84 cfm is:

$$0.0795 \text{ MW}$$

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---

The OpTiGaS static model also showed that the expanded AADairy digester site with 900 cows and 1.2 MW fuel cell system would require a 6,030 m<sup>3</sup> (213,000 ft<sup>3</sup>) gas holder tank volume with a continuous refill rate of 21.12 cfm of pure methane intended for grid power export. On the AA Dairy digester site itself, 31.84 cfm of mixed tail gas could run a fuel cell that generated 80 kW of power continuously. The 6,030 m<sup>3</sup> (213,000 ft<sup>3</sup>) gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 1,200 kW power to the spot market. However, from analysis provided by the static model the onpeak dispatch system appears to be undersized for 8 hrs/day x 5 days x 1.2 MW to the spot market. The flow chart in Figure 6.12 shows the static network model for the enlarged AA Dairy Farm with 900 milking cows.

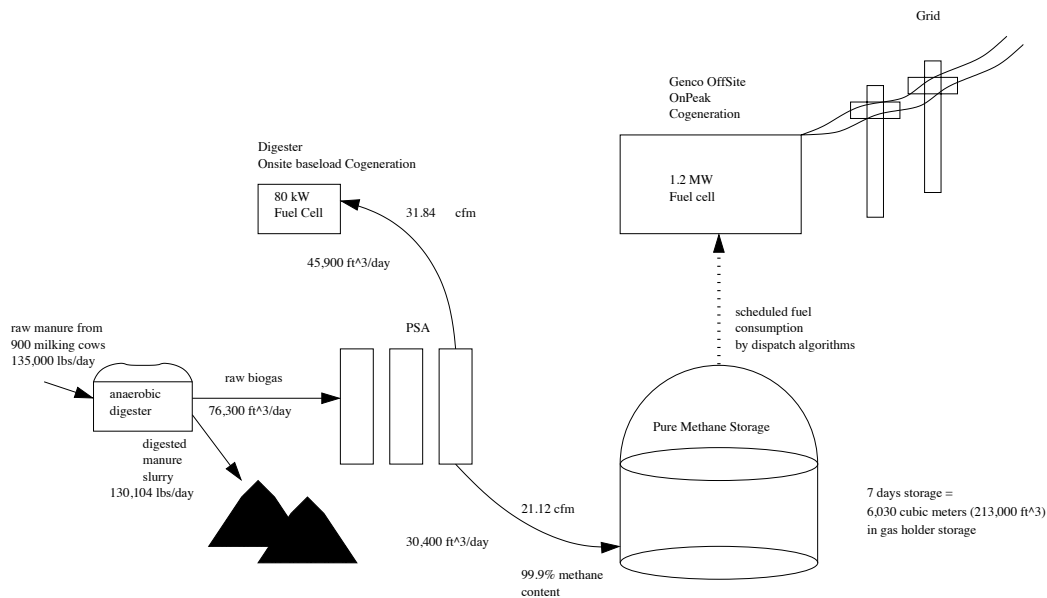


Figure 6.12: Resulting static model flow chart for AA Dairy Expanded to 900 cows case study

The power dispatch to the spot market using the 1.2 MW system connected to the 4,020 m<sup>3</sup> gas holder storage was simulated using the OpTiGaS dynamic model.

As depicted in Figure 6.13, the Genco's 1.2 MW for 4 hours/day on spot market days is almost an exact fit. The system was under capacity on one day, July 30th,

out of the 31 day period.

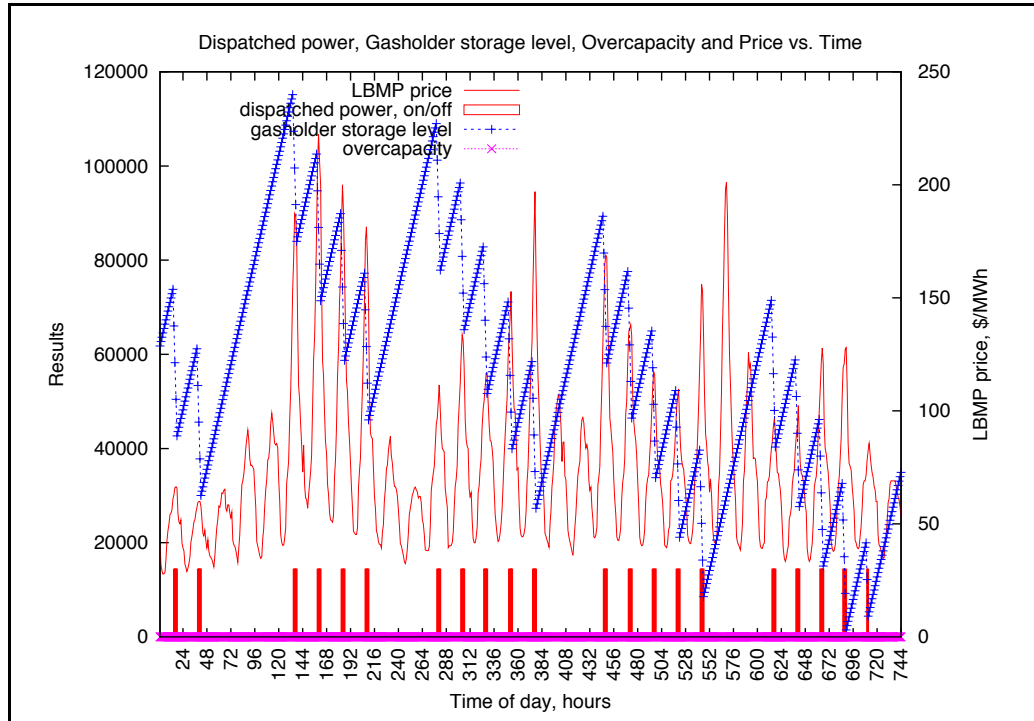
Running the system at MCFC sizes of 1.2 MW, 1.1 MW and 1.0 MW as in Figures 6.15 and 6.14, shows that 1.1 is the best trade off for respectably high revenue and maintaining a high enough methane level in the gas holder to go into the following month of spot market sales.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system.

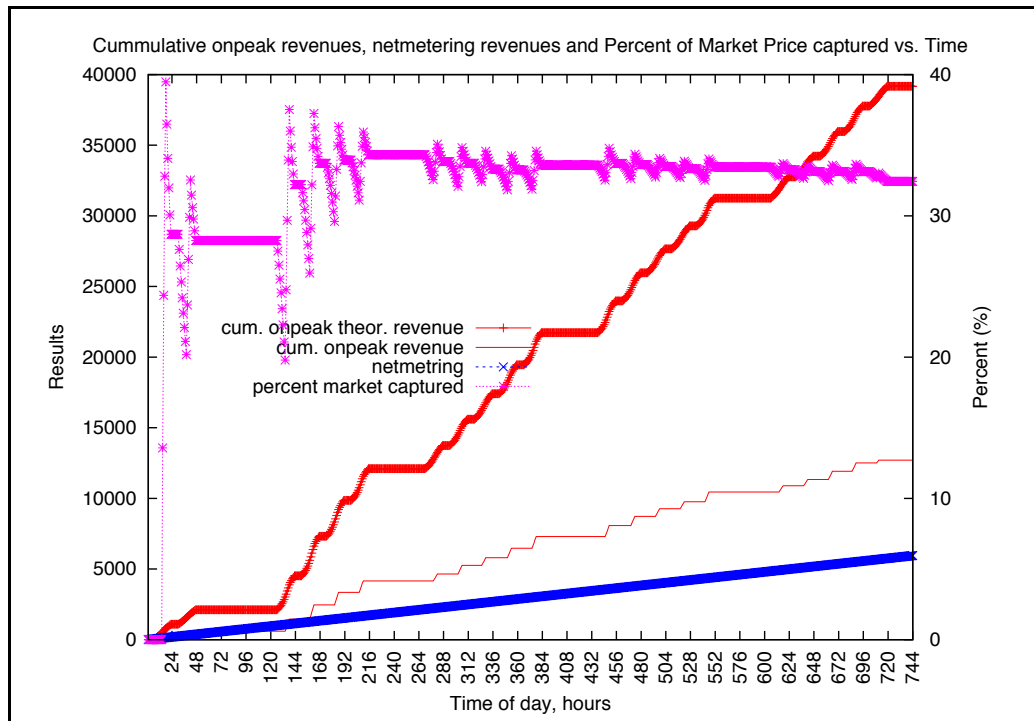
1. Biomass input = biogas from 900 milking cows
2. Gas holder size 6,030 m<sup>3</sup> for pure methane = three 2,000 m<sup>3</sup> gas holder tanks or one 6,000 m<sup>3</sup> gas holder tanks
3. Fuel cell size for onpeak generation = 1.2 MW with the flexibility to throttle down to 1.1 MW or 1 MW (4 DFC300MA fuel cells)
4. Fuel cell size for local onsite generation = 80 kW
5. Pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.
6. The farm successfully fulfilling the standard interconnection requirement document with the local utility.
7. The Genco successfully accepted to sell whole sale power to the NYISO spot market as a market participant.

[=====]



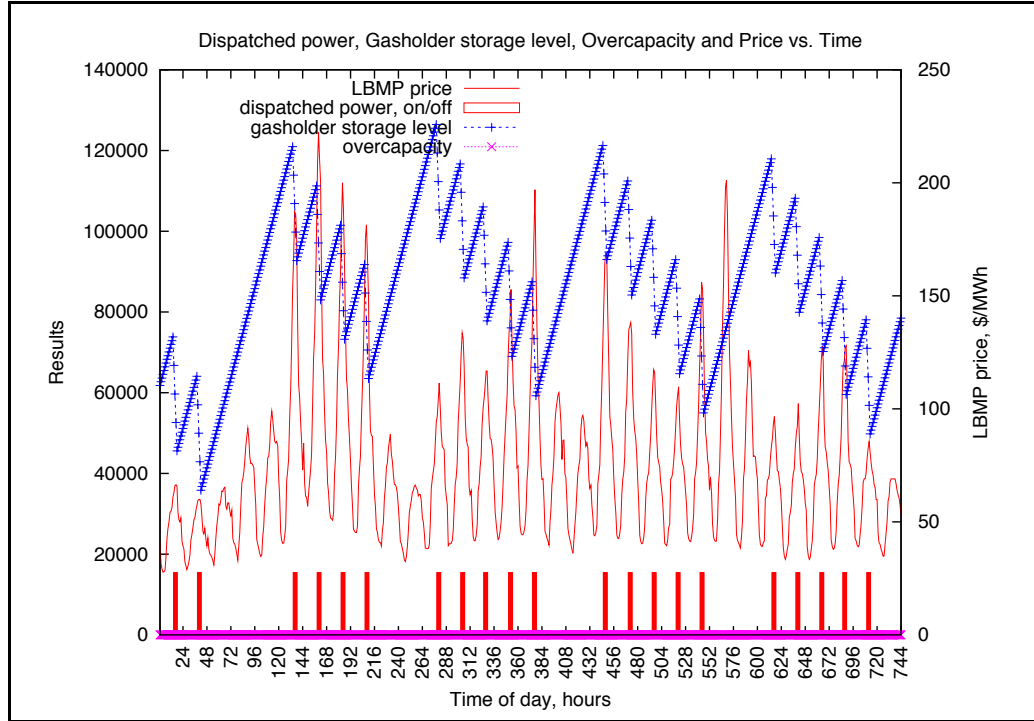


(a) AA Dairy 900 cows, 1,200 kW and 4 hrs

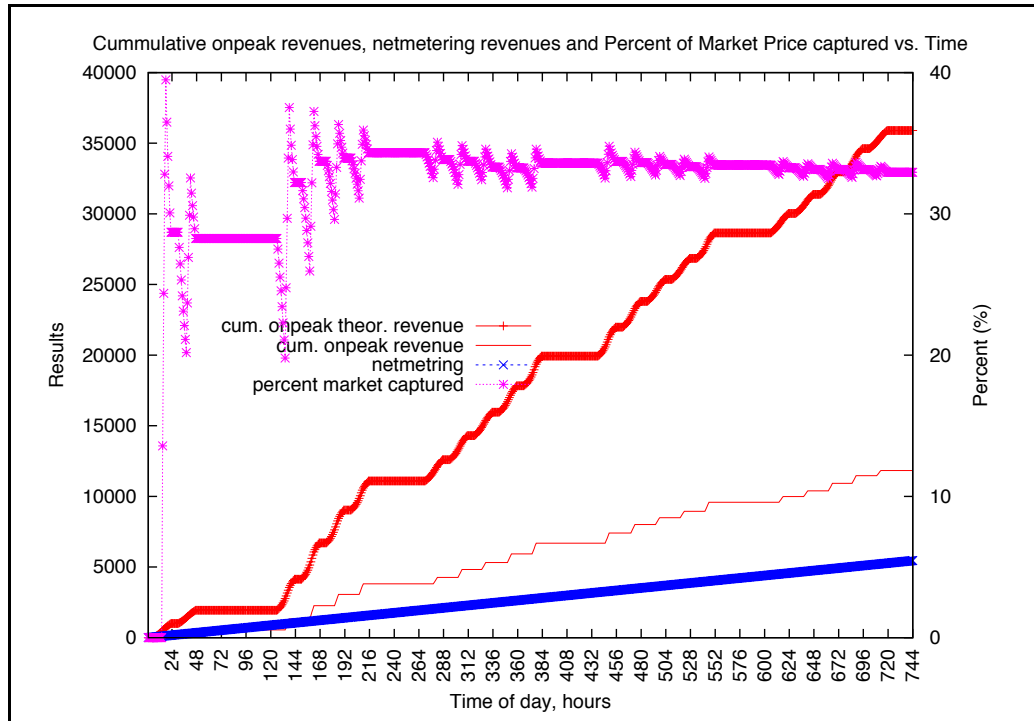


(b) AA Dairy 900 cows, 1,200 kW, 4 hrs and revenue

Figure 6.13: Expected revenue at the expansion of AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 900 cows, 1,200 kW and 4 hrs

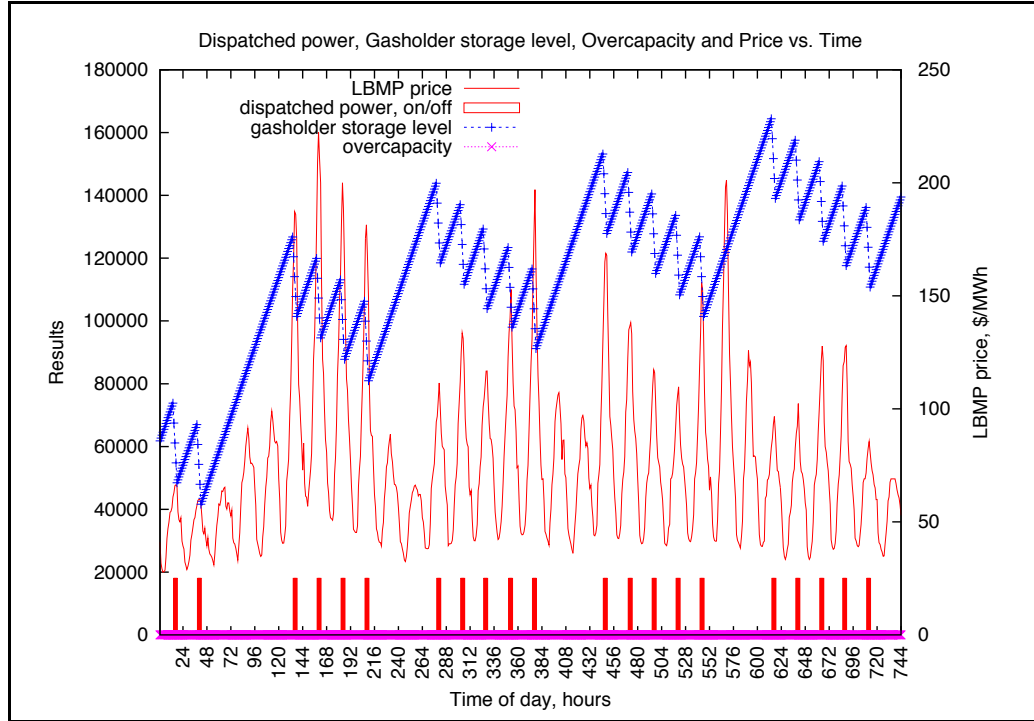


(a) AA Dairy 900 cows, 1,100 kW and 4 hrs

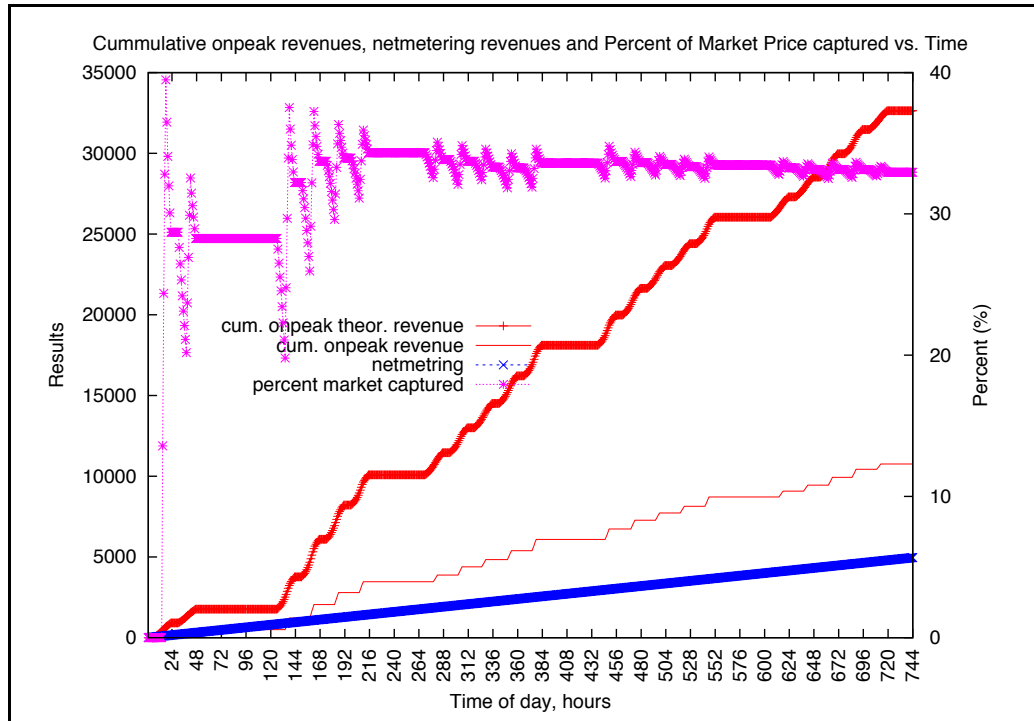


(b) AA Dairy 900 cows, 1,100 kW, 4 hrs and revenue

Figure 6.14: Expected revenue at the expansion of AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 900 cows, 1,100 kW and 4 hrs



(a) AA Dairy 900 cows, 1,000 kW and 4 hrs



(b) AA Dairy 900 cows, 1,000 kW, 4 hrs and revenue

Figure 6.15: Expected revenue at the expansion of AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 900 cows, 1,000 kW and 4 hrs

### 6.2.3 Applying OpTiGaS to AA Dairy Farm Manure & Food Waste Co-Digester Site

Given the large size of AA dairy's digester system, it may not be necessary to expand or cluster for the farm to participate in the whole sale market. Adding food waste to a manure digester significantly raises the amount of biogas produced.

Table 6.1: Comparison of observed methane yields for manure from 600 cows and various substrates, utilizing degradability ratios to estimate cow equivalents. (Modified from Source: Labatut, 2001<sup>5</sup>)

feedstock for digester	Observed NMY (mL/g TVS) at STP	number of cows
	BMP	equivalent
Manure (Man)	242.7	600
Switchgrass (Sg)	122.2	302.1
Cheese whey (W)	423.6	1047.22
Ice cream (Ic)	502.3	1241.78
Oil (O)	648.5	1603.21
Plain pasta (Pasta)	326.1	806.18
Meat pasta (Meatp)	216.2	534.49
Man:Sg 75:25	207.8	684.96
Man:W 75:25	252.4	831.97
Man:W 90:10	237.6	652.66
Man:O 75:25	360.6	1188.63
Man:Pasta 75:25	353.5	1165.22
Man:Meatp 75:25	285.6	941.41

The best performing food wastes to select based on Labatut's experiments would be used oil, plain pasta or meat pasta with a manure to food waste ratio of 75%:25%.

Without adding 1 extra dairy cow, the tripling of the biogas production is very possible at AA Dairy if the manure from the farms existing 100 dry cows and 400 young stock are trucked or piped to the digester instead of the current practice of directly spreading this manure on crop land. In Table 6.2, let us assume that

Table 6.2: Comparison of observed methane yields for manure from the equivalent of 900 cows (600 milking cows + 100 dry cows and 400 young stock) and various substrates, utilizing biodegradability ratios to estimate cow equivalents. (Modified from Source:Labatut, 2001:<sup>5</sup>)

feedstock for digester	Observed NMY (mL/g TVS) at STP	number of cows
0	BMP	equivalent
Manure (Man)	242.7	900
Switchgrass (Sg)	122.2	453.15
Cheese whey (W)	423.6	1570.83
Ice cream (Ic)	502.3	1862.67
Oil (O)	648.5	2404.82
Plain pasta (Pasta)	326.1	1209.27
Meat pasta (Meatp)	216.2	801.73
Man:Sg 75:25	207.8	1027.44
Man:W 75:25	252.4	1247.96
Man:W 90:10	237.6	978.99
Man:O 75:25	360.6	1782.94
Man:Pasta 75:25	353.5	1747.84
Man:Meatp 75:25	285.6	1412.11

adding the existing dry and young stock cows would add 50% more manure to make it look like 900 milking cows equivalent. Together with selected food waste especially used vegetable oil and pasta the AA Dairy digester could perform the biogas production of equivalent to 1,700 milking cow digester just like Patterson Farm. Therefore let us use Patterson farms best numbers again but this time it really represents AA Dairy's 600 milking cows + used oil + pasta + manure from existing young stock in a 75%:25% manure to food waste ratio. And instead of going over those Patterson like details we only simply summarize the resulting: static network model flowchart in Figure EEE, best dynamic model graph in Figure FFF and list the recommended combination of variables to implement a OpTiGaS method of dispatching power to the grid.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system at AA Dairy.

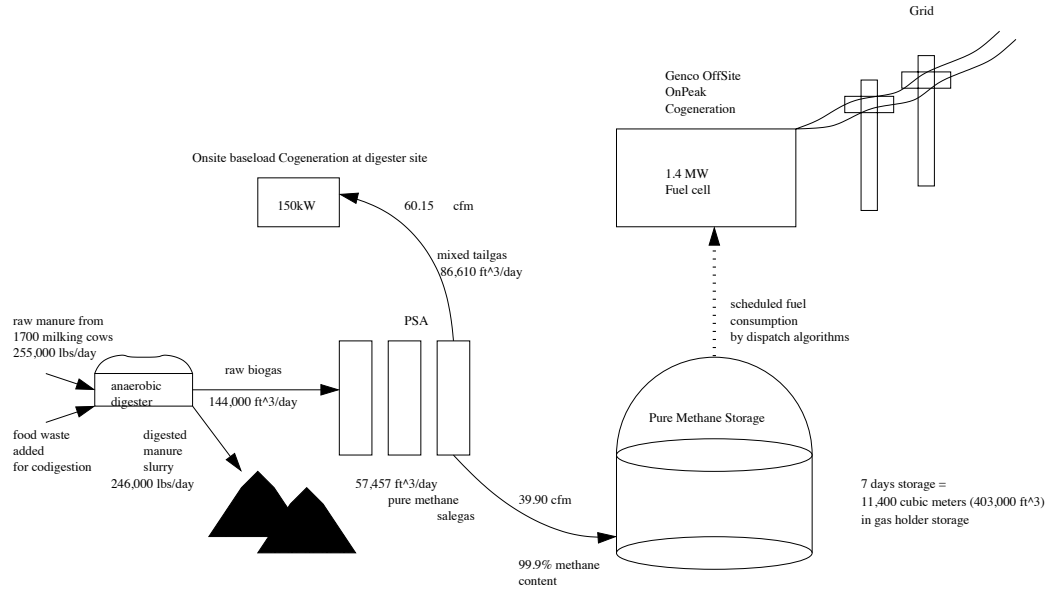
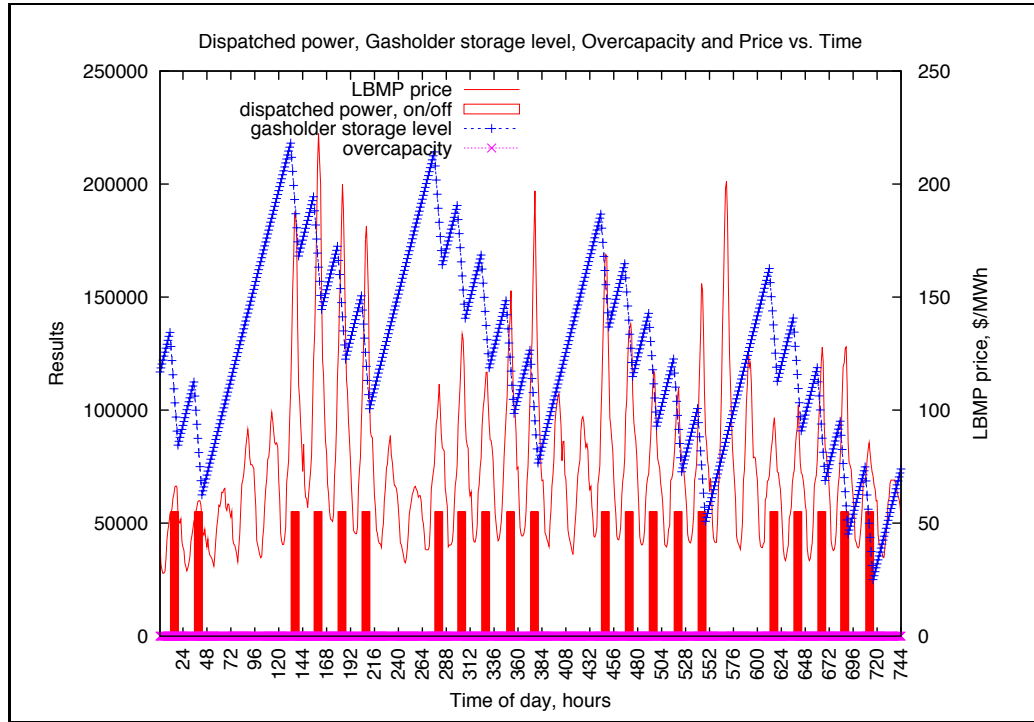
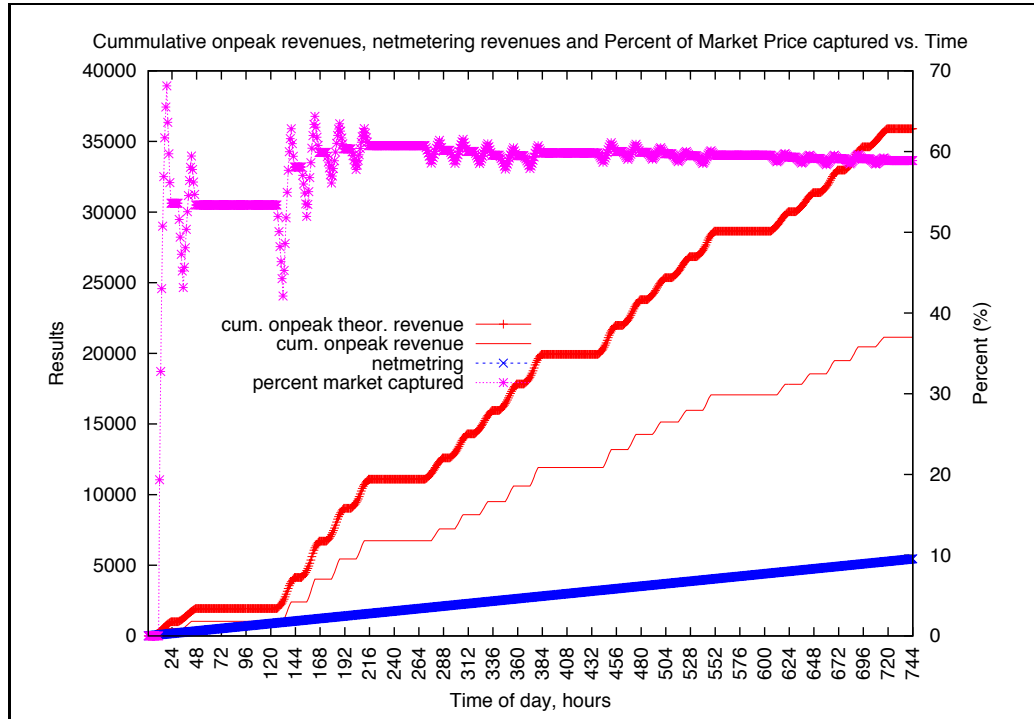


Figure 6.16: Resulting static model flow chart for AA Dairy Farm+ food waste + young stock

1. Biomass input = biogas from a minimum of 1,700 milking cows.
2. Gas holder size with volume of 11,400 m<sup>3</sup> for pure methane = six 2,000 m<sup>3</sup> gas holder tanks or two 6,000 m<sup>3</sup> gas holder tanks.
3. Fuel cell size for onpeak generation = 1.4 MW with the flexibility to throttle down to 1.1 MW or 1 MW. (FuelCell Energy Inc. manufactures the DFC-1500 which can output 1.0 to 1.4 MW of power.)
4. Fuel cell size for local onsite generation = 150 kW = a 300 kW MCFC running on dilute methane in the tail gas.
5. Pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell.
6. The farm successfully fulfilling the standard interconnection requirement document with the local utility.



(a) Foodwaste+AADairy equivalent to 1,700 cows, 1,100 kW and 8 hrs



(b) Foodwaste+AADairy equivalent to 1,700 cows, 1,100 kW, 8 hrs and revenue

Figure 6.17: Dispatched power and expected revenue at AA Dairy Farm when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for 1700 cows, a 1.1 MW generator and 8 hours/day generation.

## 6.3 Vintage Cluster Digester Site: A Cluster of Large Dairy Farms

The Vintage Dairy Farm milks about 5,000 milking cows and operates a state of the art digester system that produces and purifies biogas for direct injection into the utility's gas transmission lines. The operators of the Vintage farm system realized early on that clustering with other dairy farms in the area would improve the economic rewards of the system. They proposed a Bioenergy Solutions pipeline that would cluster seven farms in the general Riverdale, CA neighbourhood. In this cluster, biogas from more than 20,000 milking cows, dry cows and young stock would be piped to one central facility at Vintage Dairy Farm. Here, it would be purified to 99.99% pure methane, pressurized and then injected it into the PG&E natural gas pipeline as "Renewable Natural Gas (RNG)". Dairy owners in the cluster would then share revenues from the sale of gas and any emission reduction credits that apply.

The first dairy to join the Vintage cluster is Pier Van Der Hoek Dairy. Together the two farms have a total herd size of 11,400 cows. The optigas model was used to explore the economic potential of the cluster of these two farms if it could participate in the wholesale electricity market right away. The economic recession that begun in 2008 and the persistent low prices for natural gas has slowed the implementation of the cluster. This analysis would be useful going forward, in assessing the economical benefits of selling RNG vis a vis electricity.

Given inputs of 11,400 milking cows (1.71 million lbs of manure per day) and a generator size of 12 MW, the listing below shows the results of applying the static model to the current Vintage cluster.

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Determinant of A = 0.59845619



Stimulus variables input vector , b=

1,710,000.00  
1,710,000.00  
1,710,000.00  
0.00  
0.00  
12.00  
12.00

Solution output vector , x=

385,297.69  
1,647,380.26  
580,796.52  
385,297.69  
87.12  
87.12  
37.46

---

The interpretation of vector x are:

$y_{1,P1} = 385,297.69 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA;

$y_{2,P1} = 1,647,380.26$  lbs of digester slurry per day leaves the digester as effluent;

$y_{3,P1} = 580,796.52 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell;

$y_{3,P1} = 385,297.69 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage;

$y_{1,P2} = 87.12 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas;

$y_{2,P2} = 87.12 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid; and

$y_{1,P3} = 37.46 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

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Solution to 7 days of refilling the tank at 267.57 cfm with pure methane is :  
2,697,083.85 ft<sup>3</sup> or 76,372.84 m<sup>3</sup>

Compare 7 days of tank refilling 76,372.84 m<sup>3</sup>, with the following MCFC gas holder tank sizes :

5dx4hrs	5dx8hrs	7dx4hrs	7dx8hrs
53,052.93 m <sup>3</sup> ,	106,105.86 m <sup>3</sup> ,	74,274.11 m <sup>3</sup>	and 148,548.21 m <sup>3</sup>

Also the onsite generator size , based on tailgas 403.33 cfm is :  
1.0071 MW

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The flow chart in Figure 6.18 shows the static network model for the vintage cluster of farms. The OpTiGaS static model showed that with 11,400 cows and a 12 MW fuel cell system, the Genco would require a 76,373 m<sup>3</sup> (2,697,000 ft<sup>3</sup>) system of gas holder tanks with a continuous refill rate of 267.57 cfm of pure methane for grid power export. On the two farms, 403.33 cfm of mixed tail gas could run two fuel cell that generated a total of 1.007 MW (442 kW at Vintage Dairy and 565 kW at Van der Hoek Dairy) of power continuously. The 76,373 m<sup>3</sup> gas holder storage is more than sufficient to supply 4 hrs/day x 5 to 7 days at 12 MW power to the spot market. However, it appears to be undersized for 8 hrs/day x 5 days x 12 MW to the spot market.

The OpTiGaS dynamic model was used to determine the expected revenue from on peak dispatched power.

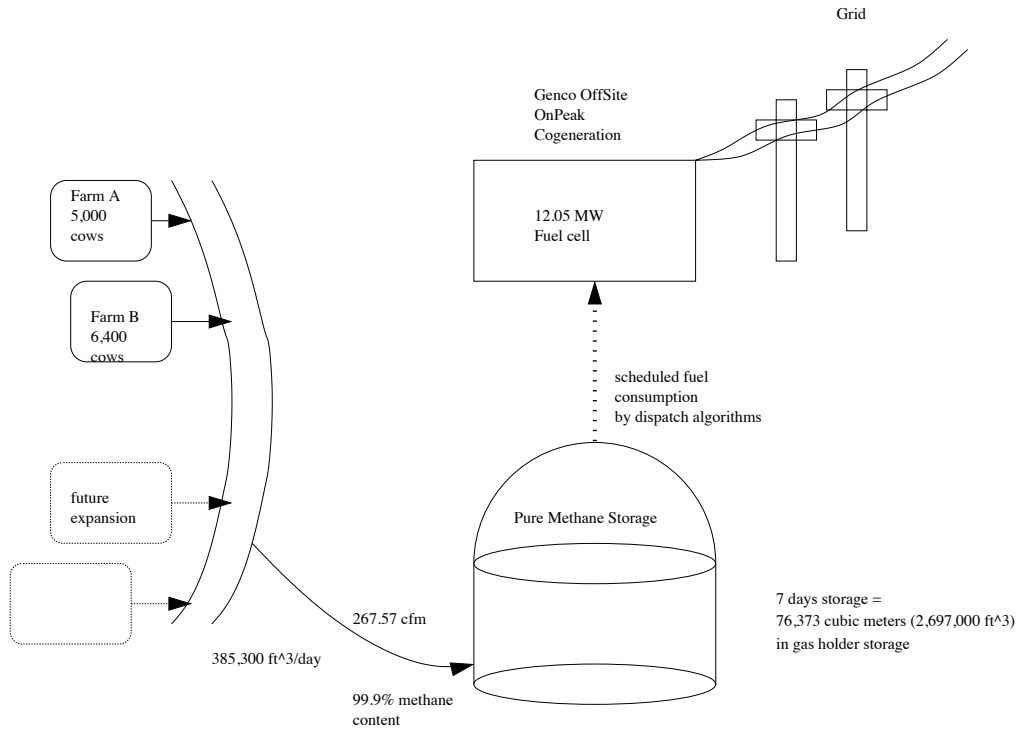


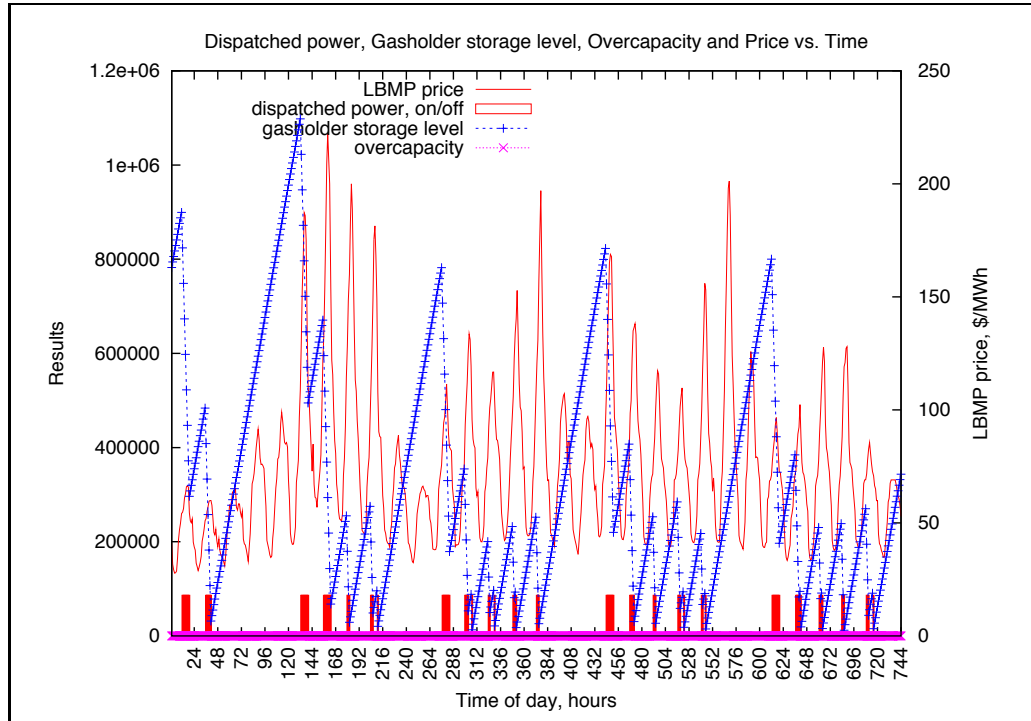
Figure 6.18: Resulting static model flow chart for Vintage Dairy Cluster case study

### 6.3.1 Applying OpTiGaS to Vintage-Clustered Farm Digester Sites

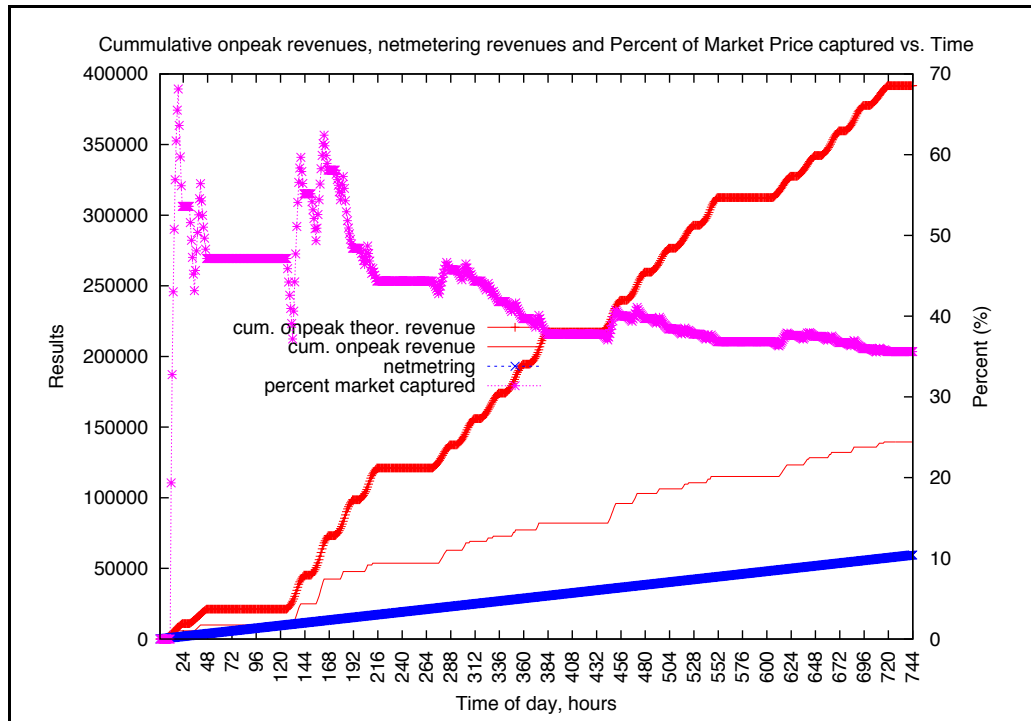
The power dispatch to the spot market using the 12 MW system connected to the 76,373 m<sup>3</sup> gas holder storage was simulated using the dynamic model. As in previous simulations, the data set was the July 2010 day ahead marginal price data.

As expected, Figures 6.19 and 6.20 show that the 12 MW for 8 hours/day on spot market days from the Vintage cluster would lead to under capacity problems with the gas holder, while 12 MW for 4 hours/day would eventually lead to overcapacity problems with the gas holder.

Running a smaller fuel cell, in the range of a 7 to 10 MW system provides a stable balance between the rate of methane consumption and maintenance of gas

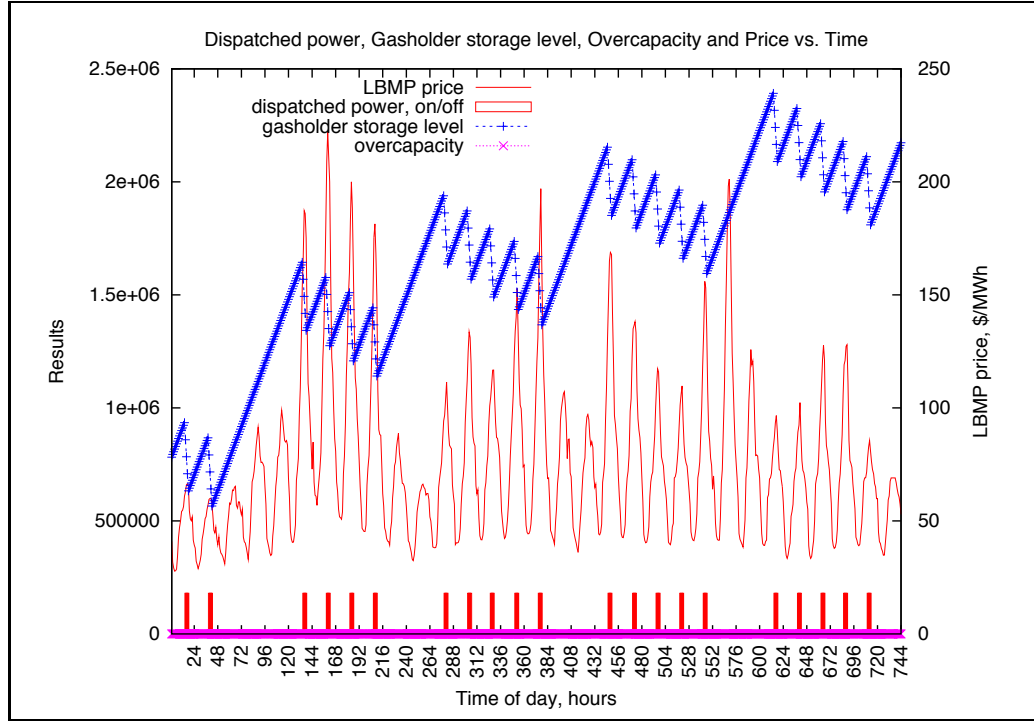


(a) Vintage Biogas cluster 11,400 cows, 12,000 kW and 8 hrs

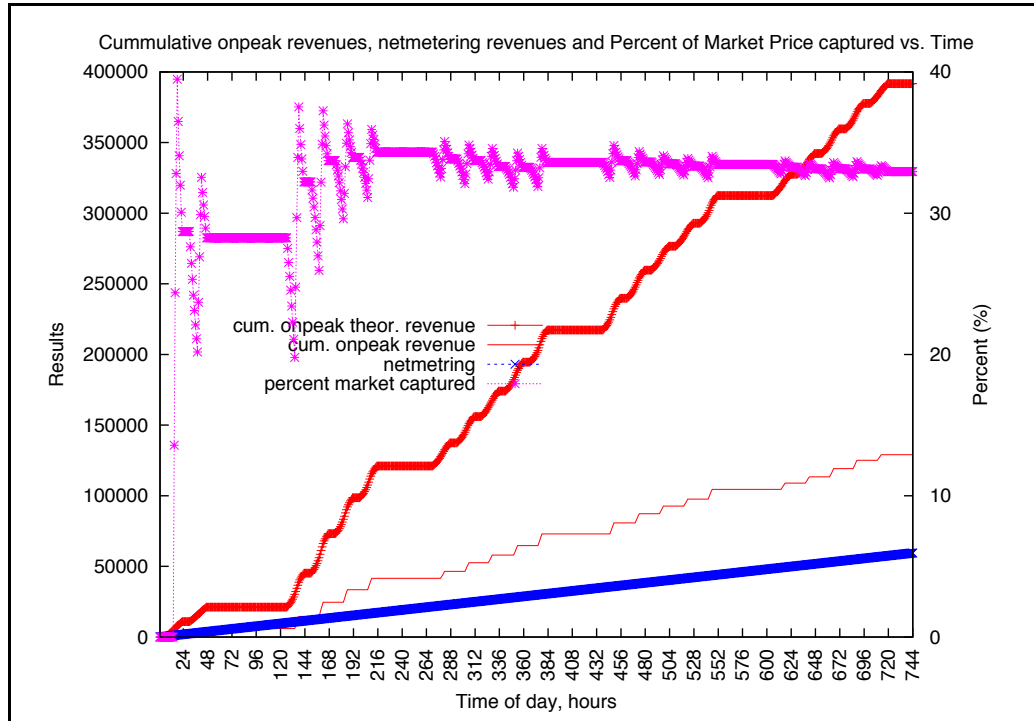


(b) Vintage Biogas cluster 11,400 cows, 12,000 kW, 8 hrs and revenue

Figure 6.19: Expected revenue at the Vintage Dairy cluster when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD ft<sup>3</sup>/day of digester biogas, 12 MW and 8 hrs



(a) Vintage Biogas cluster 11,400 cows, 12,000 kW and 4 hrs



(b) Vintage Biogas cluster 11,400 cows, 12,000 kW, 4hrs and revenue

Figure 6.20: Expected revenue at the Vintage Dairy cluster when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD  $\text{ft}^3/\text{day}$  of digester biogas, 12 MW and 4 hrs

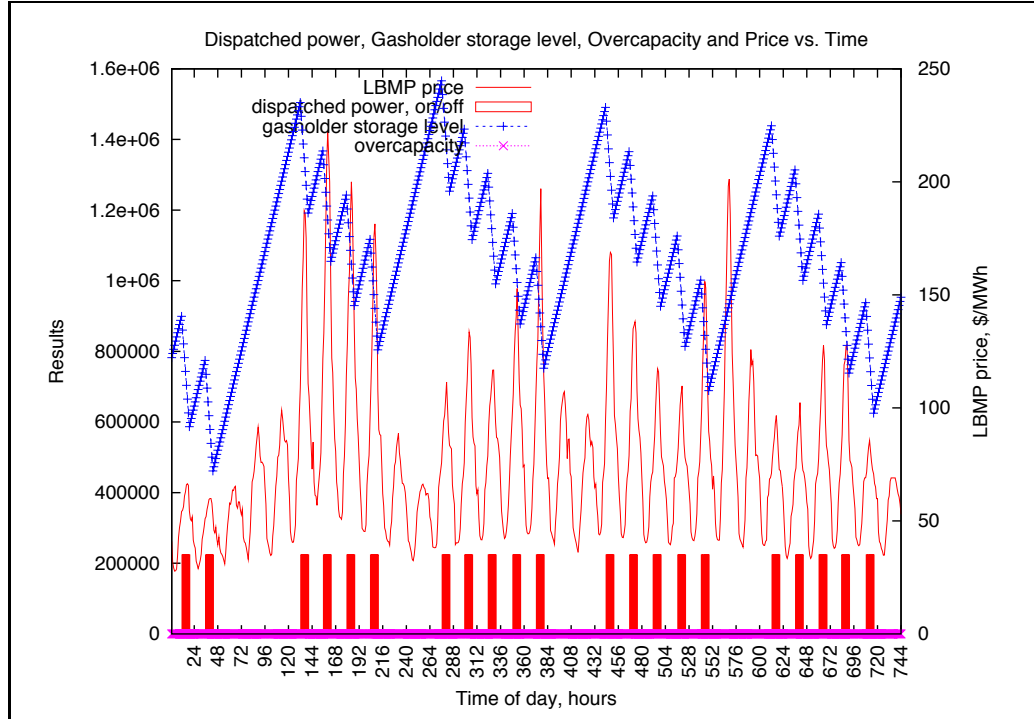
storage levels. At 7 MW, the Vintage cluster Genco could provide electricity for 8hrs/day for 7 days a week. The revenue collected by the Vintage cluster, shown in Figure 6.21 was calculated to be around \$134,533 for July 2010, representing 59% of the theoretical spot market revenue, \$228,481.

Based on the static model and then tweaking the results with the dynamic model, the following combination of parameters would be needed to implement the system.

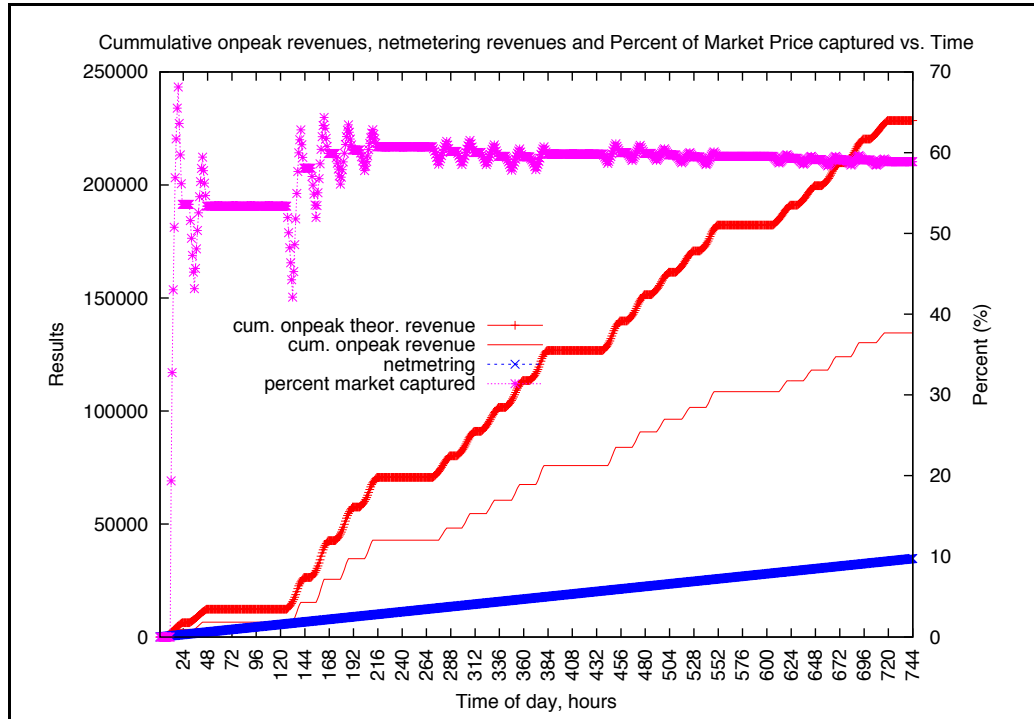
1. Biomass input = biogas from 11,400 milking cows
2. Gas holder size 76,373 m<sup>3</sup> for pure methane = inject and wheel the pressurized natural gas through the local pipeline or fill thirty-eight 2,000 m<sup>3</sup> gas holder tanks or thirteen 6,000 m<sup>3</sup> gas holder tanks
3. Fuel cell size for onpeak generation = 12 MW with the flexibility to throttle down to 7 MW by shutting off unneeded generation capacity as necessary or as per dispatch schedule.
4. Fuel cell size for local onsite generation 1.007 MW (for example three DFC-300MA MCFC at 300 kW each running on dilute methane in the tail gas)
5. A dedicated biogas pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.

## **6.4 Sunnyside Dairy Digester Site: A Large Dairy Farm**

Located in Cayuga County NY, the Sunnyside Dairy Farm has 2,700 milking cows and operates a digester site that sells power to the National Grid Company. A 500 kW genset system currently sells power to the grid by net metering. Unfortunately, much of the gas produced is in excess of the generator's fuel requirement and that



(a) Vintage Biogas cluster 11,400 cows, 7,000 kW and 8 hrs



(b) Vintage Biogas cluster 11,400 cows, 7,000 kW, 8 hrs and revenue

Figure 6.21: Expected revenue at the Vintage Dairy cluster when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD  $\text{ft}^3/\text{day}$  of digester biogas, 7 MW and 8 hrs

excess gas is simply flared off into the atmosphere. Sunnyside is also one of seven large dairy farms in a proposed 40-mile Cayuga Biogas Pipeline project. The pipeline will take biogas from the farms to a central location where it could be converted to heat, pipeline quality natural gas or electricity.

The OpTiGaS static model was used to determine the projected improvement to Sunnyside Dairy's exported electricity.

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Determinant of A = 0.59845619

Stimulus variables input vector , b=

405,000.00

405,000.00

405,000.00

0.00

0.00

2.00

2.00

Solution output vector , x=

91,254.72

390,169.01

137,557.07

91,254.72

14.52

14.52

6.24

---

---

The interpretation of vector x are:

$y_{1,P1} = 91,254.72 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA;

$y_{2,P1} = 390,169.01$  lbs of digester slurry per day leaves the digester as effluent;



$y_{3,P1} = 137,557.07 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously;

$y_{3,P1} = 91,254.72 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage;

$y_{1,P2} = 14.52 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas;

$y_{2,P2} = 14.52 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 6.24 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

---

---

Solution to 7 days of refilling the tank at 63.37 cfm  
with pure methane is:

$$638,783.02 \text{ ft}^3 \text{ or } 18,088.30 \text{ m}^3$$

Compare 7 days of tank refilling 18,088.30  $\text{m}^3$ , with the  
following MCFC gas holder tank sizes:

4hrsx5d	8hrsx5d	4hrsx7d	8hrsx7d
8,842.16 $\text{m}^3$ ,	17,684.31 $\text{m}^3$ ,	12,379.02 $\text{m}^3$	and 24,758.04 $\text{m}^3$

Also the onsite generator size, based on tailgas 95.53 cfm is:

$$0.2385 \text{ MW}$$

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The OpTiGaS static model showed that the Sunnyside digester site and generator company with 2,700 cows and a 2 MW fuel cell system would require a 18,088  $\text{m}^3$  (638,800  $\text{ft}^3$ ) system of gas holder tanks with a continuous refill rate of 63.37 cfm of pure methane for grid power export. On the farm site itself, 95.53 cfm of mixed tail gas could run a fuel cell that generated a total of 240 kW of power

continuously. The 18,088 m<sup>3</sup> gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 2 MW power or 8 hrs/day x 5 days x 2 MW to the spot market. The flow chart in Figure 6.22 shows the static network model for Sunnyside Dairy Farm.

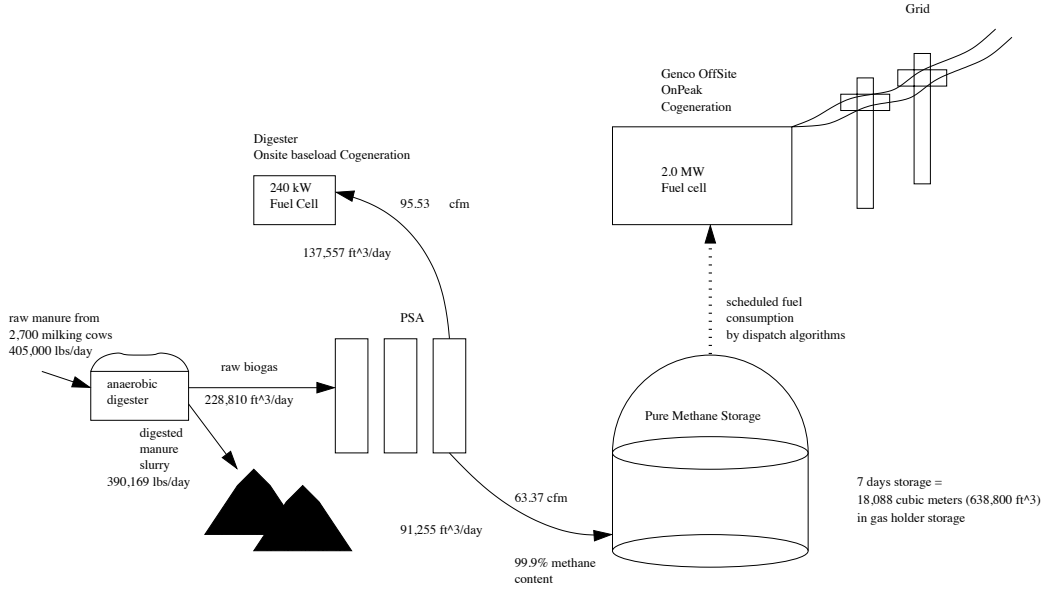


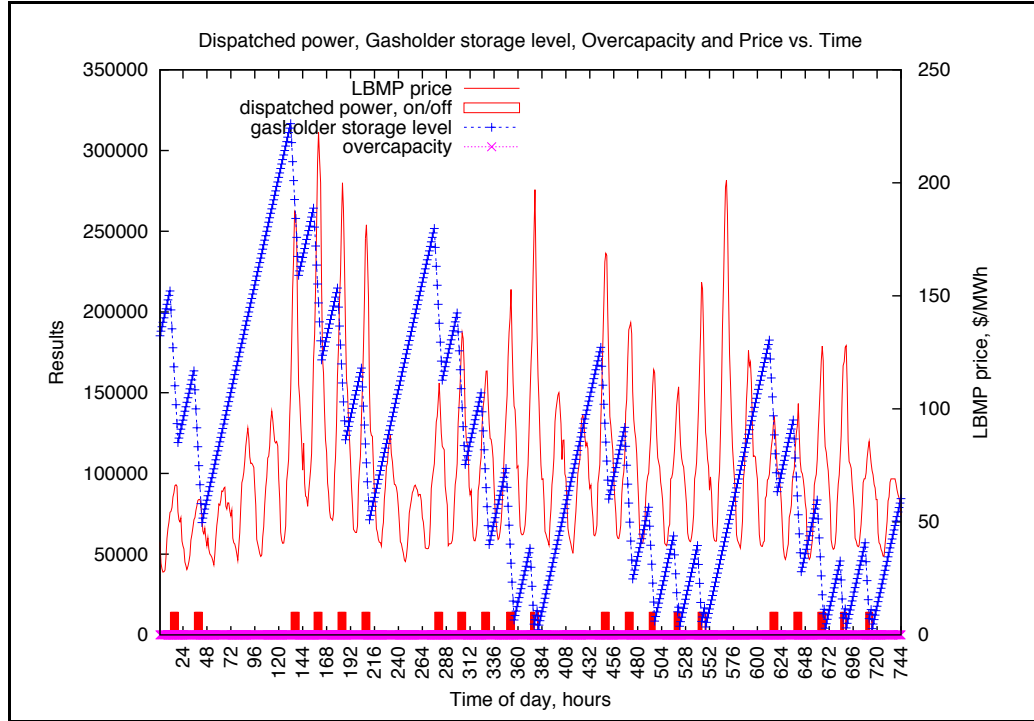
Figure 6.22: Resulting static model flow chart for the Sunnyside Dairy case study

The OpTiGaS dynamic model was used to determine the expected revenue from on peak dispatched power.

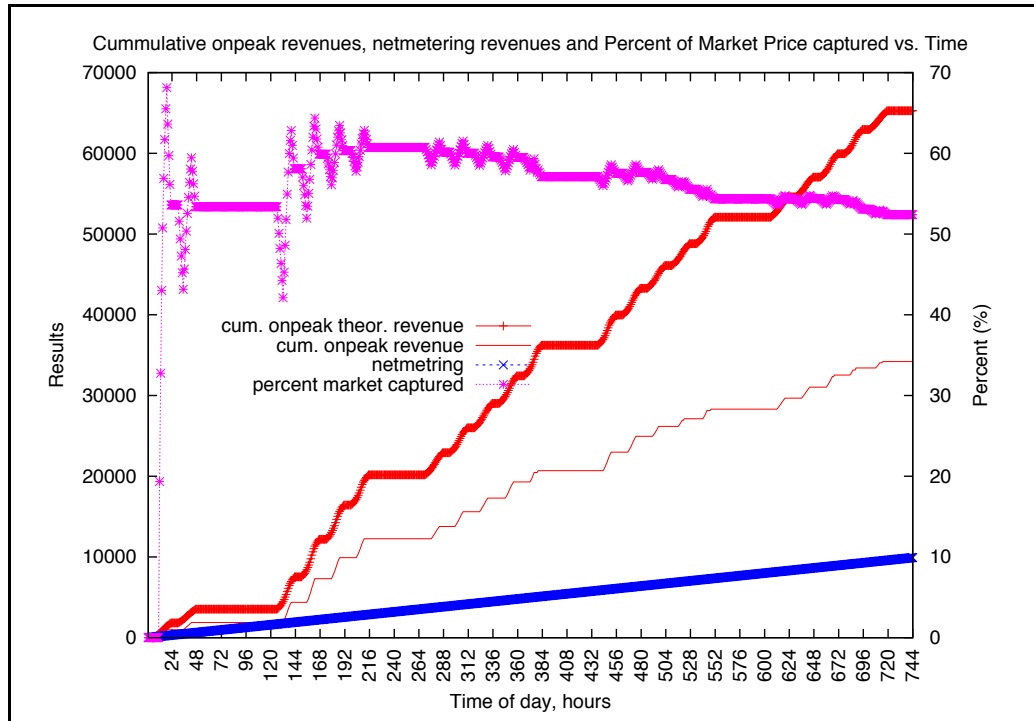
#### 6.4.1 Applying OpTiGaS to Sunnyside Farm Digester site

The power dispatch to the spot market using the 2 MW system connected to the 18,088 m<sup>3</sup> gas holder storage was simulated using the dynamic model. The data set was from NYISO in July 2010 and specifically the day ahead marginal price data.

It is observed in Figure 6.23 that the 2 MW for 8 hours/day on spot market days from Sunnyside Dairy would lead to under capacity problems with the gas holder.



(a) Sunnyside Dairy 2,700 cows, 2,000 kW and 8 hrs



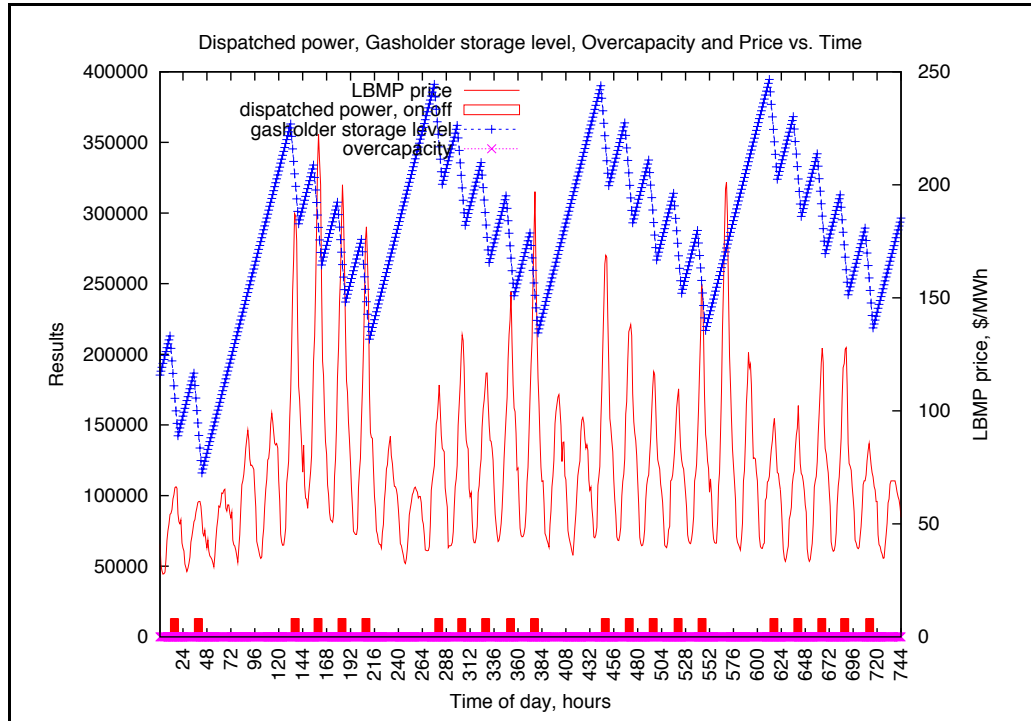
(b) Sunnyside Dairy 2,700 cows, 2,000 kW, 8 hrs and revenue

Figure 6.23: Expected revenue at the Sunnyside Dairy when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD ft<sup>3</sup>/day of digester biogas, 2 MW and 8 hrs

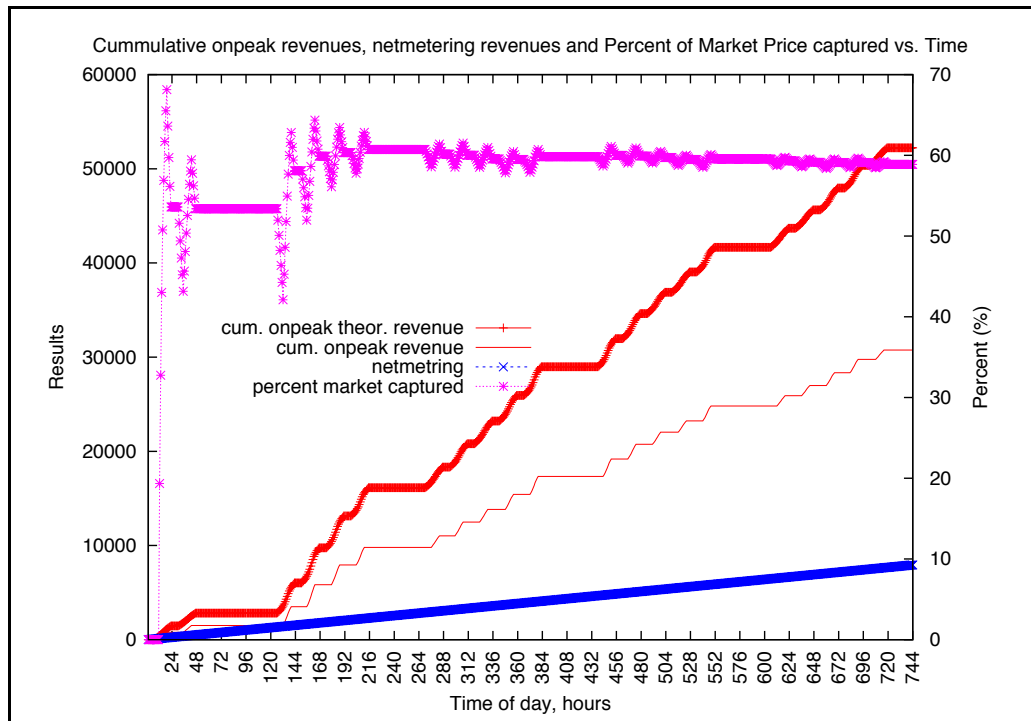
Running the fuel cell for 8hrs/day x 1.6 MW instead provided a remedy to methane consumption while maintaining gas storage levels. The revenue collected by Sunnyside Dairy and the Genco, shown in Figure 6.24, was calculated to be around \$30,750 for July 2010, representing 59% of the theoretical spot market revenue, \$52,224.

Based on the static model and then tweaking those static results for the dynamic model, the following combination of parameters would be needed to implement the system.

1. Biomass input = biogas from 2,700 milking cows
2. Gas holder size 18,088 m<sup>3</sup> (638,800 ft<sup>3</sup>) for pure methane = inject and wheel the pressurized natural gas through the local pipeline or fill nine 2,000 m<sup>3</sup> gas holder tanks or three 6,000 m<sup>3</sup> gas holder tanks
3. Fuel cell size for onpeak generation = 2.0 MW with the flexibility to throttle up or down individual units to 1.4 MW by shutting off unneeded generation capacity as necessary or as per dispatch schedule.
4. Fuel cell size for local onsite generation = 240 kW (one DFC-300MA MCFC at 300 kW each running on dilute methane in the tail gas)
5. A dedicated biogas pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.
6. The farm successfully fulfilling the standard interconnection requirement document with local utility.
7. The Genco successfully accepted to sell whole sale power to the NYISO spot market.



(a) Sunnyside Dairy 2,700 cows, 1,600 kW and 8 hrs



(b) Sunnyside Dairy 2,700 cows, 1,600 kW, 8 hrs and revenue

Figure 6.24: Expected revenue at the Sunnyside Dairy when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD ft<sup>3</sup>/day of digester biogas, 1.6 MW and 8 hrs

CHAPTER 7

**APPLICATIONS AND RESULTS FOR SENECA FOODS  
MONTGOMERY PLANT**

## **7.1 Introduction**

Two approaches were used to analyse Seneca Foods Corporation. First the traditional biogas potential method with net metering. Secondly the new OpTiGaS method developed in this thesis was applied to compare the different recommendations that arose.

## **7.2 Traditional Approach for Electrical Power Base Load**

### **Sales from Biogas to the Retail Market**

Two site visits to the Seneca Foods Corporation (SFC) Montgomery packing plant in fall 2005 and subsequent trips to Denmark and Germany in early 2006 were undertaken with Seneca Foods executives to determine the best way to reduce the company's post-hurricane Katrina and post-Hurricane Rita \$5 million over spending for fuel in 2005. These bioenergy investigations reignited the company chairman Art Wolcott's interest in using their sweet corn residues (fibres and cobs from ears of corn with small amounts of kernels) to make methane with a digester system. Mr. Walcott said that if we devised a workable system at Montgomery, there were at least ten (10) similar Seneca Foods food packing sites around the USA that could copy the system. The problem we were try to solve arose because SFC was unable to continuously use a huge digester that was custom-built for them by AnAerobics (now renamed Ecovations) due to cost over runs at AnAerobics and the eventual divorce of the two companies a few months before the digester

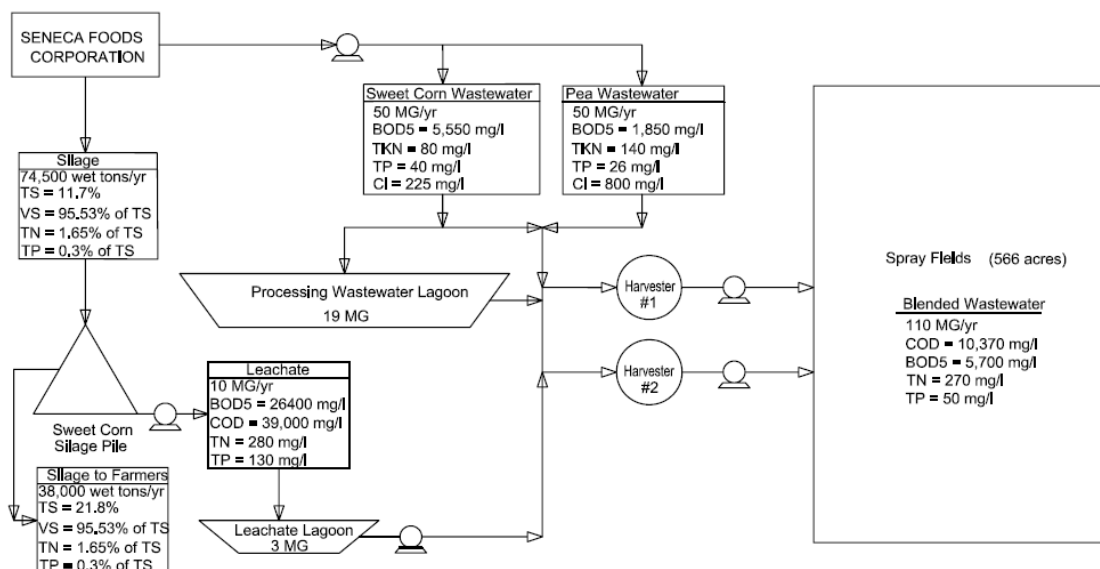


Figure 7.1: Previous wastewater treatment system for Seneca Food waste streams was intended to be brought up to steady state biogas production and influent logistics/material handling. Figures 7.1, 7.2 and 7.3 show the previous waste handling method at Seneca Food; followed by AnAerobics original design for the digester system; and the eventual interim design, which SFC tried to implement unsuccessfully did in the absence of AnAerobics involvement.

In the trip to Denmark in January 2006, mostly huge centralized manure digesters operated by farm cooperatives was seen. Some industrial waste, slaughter house products and imported fish oils were added but the primary raw material was swine waste. The Danes were conservative and wanted to work with very predictable substrates like manure. However university researchers like Byorg Nordal and companies like Xergy and BIOSCAN offered to build custom digester systems based on “Danish technology” to convert the sweet corn residues to biogas, electricity and thermal energy.

The next trip was to Germany at the end of March 2006. There we mainly looked at corn digesters which used the whole crop, ears, grain and stover, with manure for inoculum. Systems got higher subsidies for corn only and if they

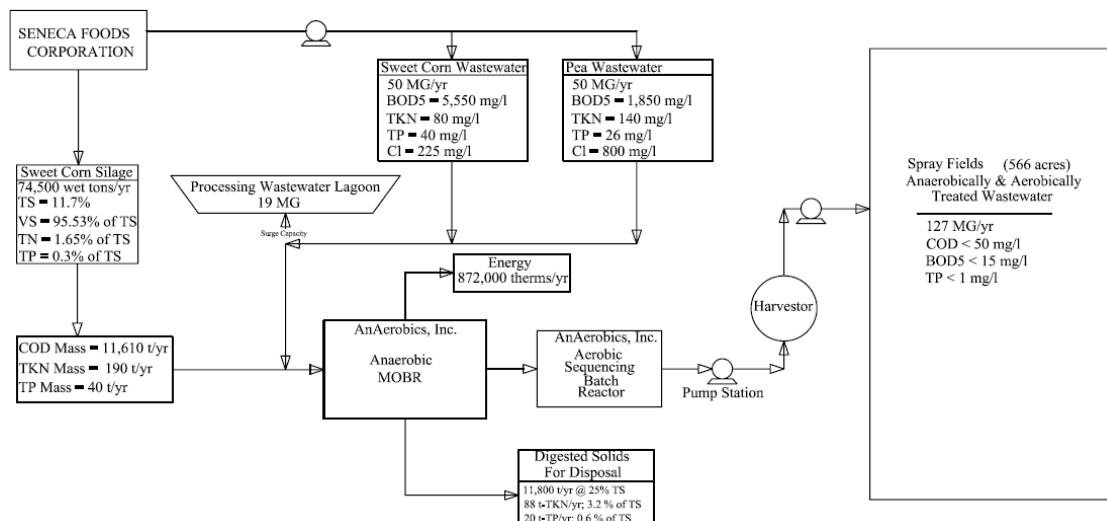


Figure 7.2: Proposed Anaerobically treatment system for Seneca Food waste streams for discharge on the land

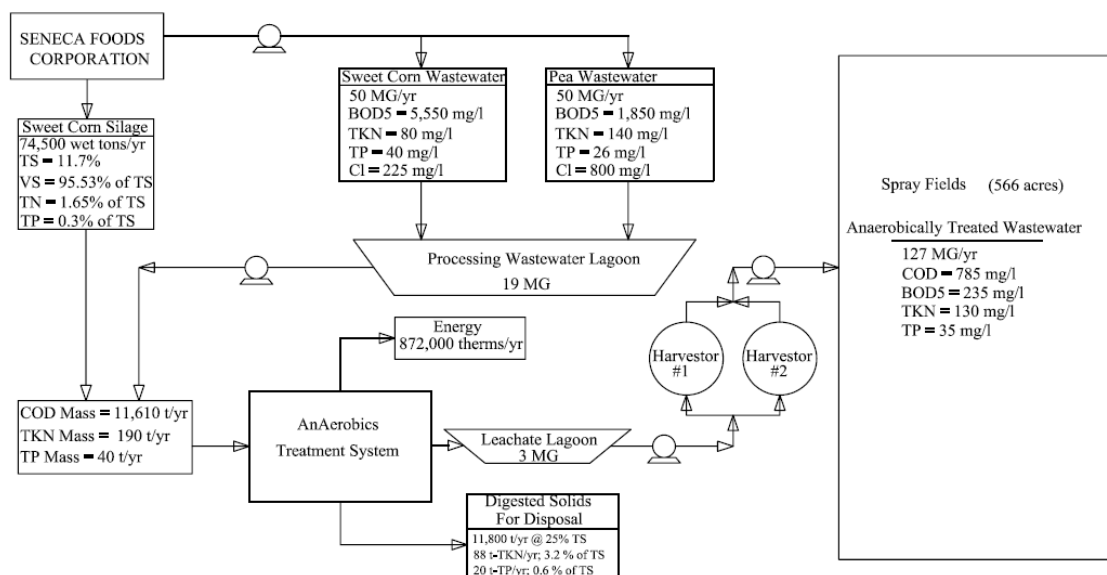


Figure 7.3: As-built Anaerobically treatment system for Seneca Food waste streams for discharge on the land



encourage family farms to stay in production. Nobody did leachate digesters because of the ease of which it went unstable and the many variables needed to control steady state anaerobic digestion. That said Seneca Foods had a challenge facing them if they did leachate only. Andreas G., Felipe Kaier and Mathias Effenburger from lfe.de agreed to help analyze the sweet corn silage and leachate samples for BMP and suitability of leachate only digesters using their state-of the art mini crop digester. We are awaiting the results.

In the mean time a team was assembled to suggested how to renovate the digester, start it up and reach steady state with just leachate. In section below are the steps used to advice Seneca Foods how to substitute corn waste energy for natural gas consumption.

A back of the envelope design for using the corn and sweet pea waste material was done first followed by a more thorough lab based feedstock analysis. Based on the back of the envelope analysis the simple flow chart in Figure 7.4 and assumptions in Table 7.1 were made. More than 97 million to 291 million cubic feet of biogas was projected from running the plant during the 3 to 4 summer peak months, ie in excess of 1 million to 3.3 million cubic feet of biogas per day.

For the remainder of this section the potential for biogas production from sweet corn biomass at the Seneca Foods Montgomery Plant is addressed. Based on analyses of the material that was provided to Cornell, and results from other laboratories, the suitability of this biomass for anaerobic digestion was assessed, and methane production that would result from anaerobic digestion was predicted. Predicted biogas production was compared to natural gas consumption.

Industrial anaerobic digestion in the United States has primarily centered on manure from concentrated animal feeding operations (CAFOs), and high strength industrial wastes. Although it is a main source of biogas production, anaerobic

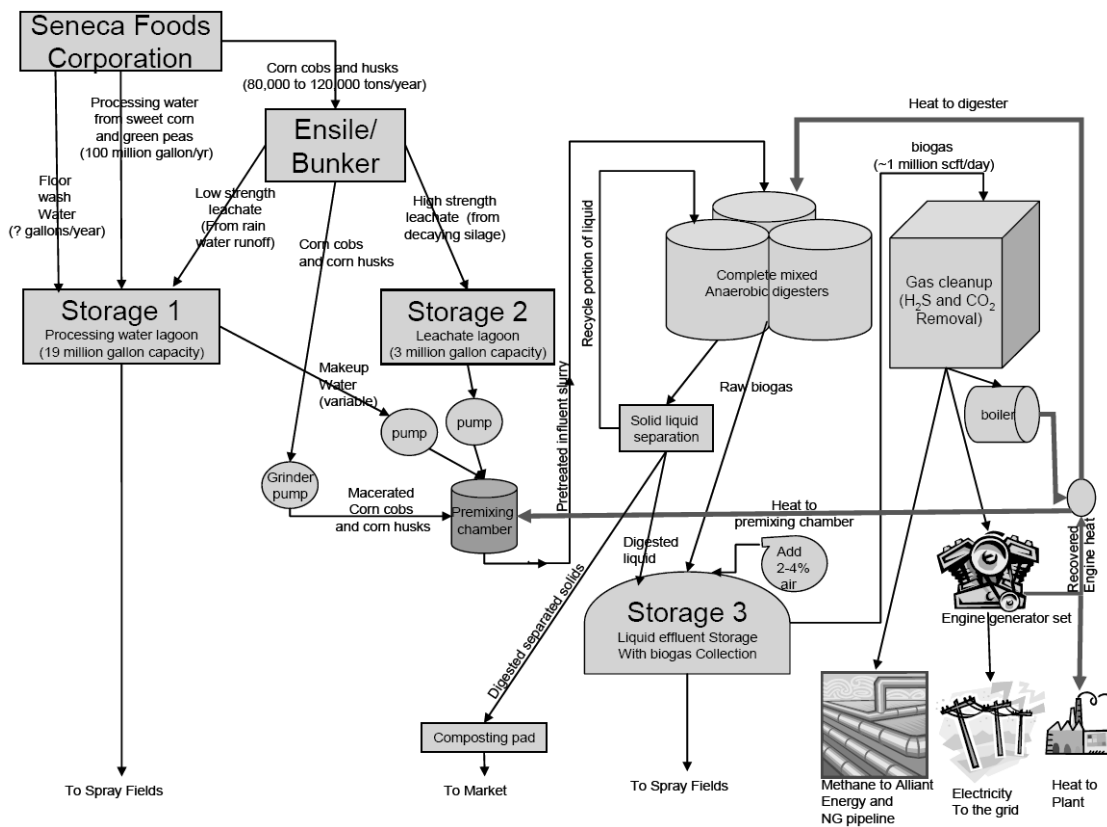


Figure 7.4: Back of the envelope design for SFC Montgomery Plant.

Table 7.1: Assumptions for Seneca Foods Digester

Assumptions for Seneca Food Digester Project									
	365 day operation		Per day	365 day operation		Per day	90 day operation		day operation
	full size	0.33		Digester Size	Per year		full size	0.33	
tons/year of stover	80000	26667	219	73	80000	889	Per year	Per year	Digester Size
TS	12.00%	12.00%			12.00%		26667	26667	Per day
tons of solids	9600	3200	26	9	9600	107	12.00%	12.00%	296
target concentration of digester	8.00%	8.00%			8.00%		3200	3200	36
tons of digester influent mix	120000	40000	329	110	120000	1333	8.00%	8.00%	
gallons of digester influent mix	29268293	9756098	80187	26729	29268293	325203	40000	40000	444
tons of water added	110400	36800	302	101	110400	1227	9756098	9756098	108401
gallons of water added	26926829	8975610	73772	24591	26926829	299187	36800	36800	409
HRT	20	20					8975610	8975610	99729
Total Digester capacity needed (gal)			1603742	534581		6504065	20	20	
(cubic feet)			214404	71468		869527			2168022
# of digesters			3	1		6			289842
sub-digester size (gallons/cf)	534581	534581	71468	71468	1084011	144921	1084011	1084011	144921
Diameter (ft)			45	45		56			56
resulting height (ft)			44.94	44.94		58.84			58.84
height to diameter ratio			1	1		1.05			1.05
Target biogas production	600000		ft <sup>3</sup> biogas/day						
biogas production rate (m3/m3:ft3/ft3)	75								
resulting production from operation	290322581	96774194	795404	265135	290322581	3225806	96774194	96774194	1075269
	ft3/yr	ft3/yr	ft3/day	ft3/day	ft3/yr	ft3/day	ft3/yr	ft3/yr	ft3/day

digestion in the US has been implemented primarily for odor control, and water quality and manure and municipal sludge waste management, with biogas energy production as a welcomed byproduct. Other countries have focused more on renewable energy production. In Europe, recent greenhouse gas reduction initiatives including the Kyoto agreement led many governments to set quotas and offer incentives for energy derived from renewable resources such as maize, ryegrass, and household waste. Whole crop corn is an important substrate for anaerobic digestion, representing more than half of the material used for digesters in Germany.<sup>93</sup> Because crop production can only occur during the growing season, while many digesters are run year-round, ensiling crops is a common means of storing biomass prior to anaerobic digestion.<sup>93,94</sup> Anaerobic digestion of the sweet corn silage from the Montgomery plant is therefore not an unusual problem.

### **7.2.1 Approach**

One strategy for assessing the economic feasibility of a digestion system is to determine if the methane production from corn silage anaerobic digestion can be used to offset the annual natural gas consumption. Six silage samples collected from the storage bunker at the Montgomery plant were analyzed with the objectives of determining the suitability of the material for anaerobic digestion, and predicting the quantity of methane that could be produced from anaerobic digestion. We measured total solids (TS), volatile solids (VS), pH, total nitrogen (N), ammonia N, and volatile fatty acid concentrations (see Table 7.2). Procedures followed Standard Methods<sup>95</sup> or NREL procedures,<sup>96</sup> except for pH, which followed Neureiter et al.,<sup>94</sup> and VFA determination, which was carried out by a commercial laboratory. Additional data from BIOSCAN A/S, UC Laboratory, and Anaerobics were provided by Seneca Foods.

We predicted biogas production potential from VS contents and observed methane yields from anaerobic digestion of similar wastes from several published studies. Corn plant material, including stover, stalks, leaves, and whole crop, has been successfully digested in numerous studies, with CH<sub>4</sub> yields ranging from 2.9 to 8.6 ft<sup>3</sup>/lb VS (0.18-0.54 m<sup>3</sup>/kg VS).<sup>93,94,97-99</sup> The lowest of these values are uncommon, and the highest are from batch reactors, and are generally not attainable in intermittently-fed reactors. Ensiled corn has generally shown higher yields than fresh material<sup>94</sup> (Neureiter et al. 2005). We used a low, typical, and high yield, 4.0, 4.8, and 6.4 ft<sup>3</sup> CH<sub>4</sub>/lb VS, respectively, to predict CH<sub>4</sub> production.

Predicted methane production was compared to natural gas consumption by the Montgomery plant. Monthly natural gas consumption data were provided by Seneca Foods for 2004 and 2005. The average value for these two years was assumed to represent a typical year.

## 7.2.2 Results and Discussion

### Composition

Total solids, VS, and total N concentrations were similar across laboratories when expressed per unit TS. Nitrogen concentrations are expected to be sufficient for anaerobic digestion. Assuming a C concentration of 47%,<sup>98</sup> the C:N ratio is 28:1, which is within the optimal range for anaerobic digestion, 20-30.<sup>100</sup> Moreover, whole corn plant material with a similar N concentration has successfully been digested at high rates and high CH<sub>4</sub> yields.<sup>94,98</sup>

Most of the analyzed sample showed low pH, which is ideal for long term storage without significant energy content losses, but well below the optimum for anaerobic digestion, pH 7-8.<sup>101</sup> The low pH suggests that batch or plug-flow digesters would not be a good approach for anaerobic digestion of this biomass. The

low pH is caused by accumulation of volatile fatty acids (VFAs) during microbial fermentation. Volatile fatty acids are important substrates for methanogenesis, but can be toxic to methanogens at high concentrations. These conditions suggest that a complete mixed reactor would be the most suitable for this material.

Volatile solids generally make up > 90% of the TS of this material. This result is similar to other measurements on corn plant material, and suggests a high potential for methane production.<sup>94,98</sup> Volatile solids concentrations, when expressed per unit wet mass, show a very large variation, primarily due to variation in water content. Since VS concentration is important in determining biogas production, better estimates of biogas production will require more certainty in total VS concentrations.

### **Natural gas consumption and potential biogas production**

The annual natural gas consumption at the Montgomery Plant was approximately 110 million ft<sup>3</sup> (3.1 million m<sup>3</sup>). The mean monthly natural gas consumption at the Seneca Foods Montgomery Plant is shown in Table 7.3. The data in Table 7.3 show that 65% of the natural gas consumed at the Montgomery plant is used in the three-month period of July, August, and September. Eighty percent of the total usage occurs from June to October, and 98% of the total usage occurs from June through the following March. The remaining 2% of natural gas consumption takes place from April through May. Daily patterns of natural gas usage from 2004 are shown in Figure 7.5. Peak daily consumption for both years was in August. In 2004, the peak daily consumption was 13,600 therms on August 28, while the peak was 12,000 therms on August 25 in 2005.

Biogas production predictions are given in Table 7.4. We predicted CH<sub>4</sub> production from anaerobic digestion of sweet corn biomass at 96, 190, and 420 million ft<sup>3</sup>/yr. Our typical prediction of CH<sub>4</sub> production is lower than both predictions

Table 7.2: Characteristics of sweet corn silage and leachate.

Sample <sup>a</sup>	pH	Total solids (% of wet mass)	Volatiles solids (% of TS)	Volatiles solids (% of wet mass)	Total N (% of TS)	Ammonia N (mg N/kg wet)	Total VFAs (% of TS)
Cornell A	3.84	16.1	96.2	15.4	1.7	345	19.9
Cornell B	3.68	26.6	88.8	23.6	1.4	290	11.3
Cornell C	3.79	28.9	93.6	27	1.5	340	10
Cornell D	3.62	21.1	94.9	20.1	1.6	260	16
Cornell E	3.78	16.2	90.8	14.7	1.4	20	2
Cornell F	3.82	15.8	94.4	14.9	2.2	300	20.1
Cornell mean	3.76	21.7	92.5	20.1	1.6	260	13.2
BIOSCAN	4	21	97.6	20.5	1.7		
AnAerobics		11.7	95.5	11.2	1.7		
UC Lab Silage A	6.24	17.6	97.1	17.1	1.3	100	
UC Lab Silage B	6.12	15.5	92.5	14.3	0.9	300	
UC Lab Leachate A	3.87	2.78	80.9	2.25	2.97	6800	
UC Lab Leachate B	3.6	1.58	79.8	1.26	2.42	11600	
Cornell Leachate		1	71.2	0.7			

<sup>a</sup>Notes: All of the Cornell samples were collected in later 2005 or early 2006.

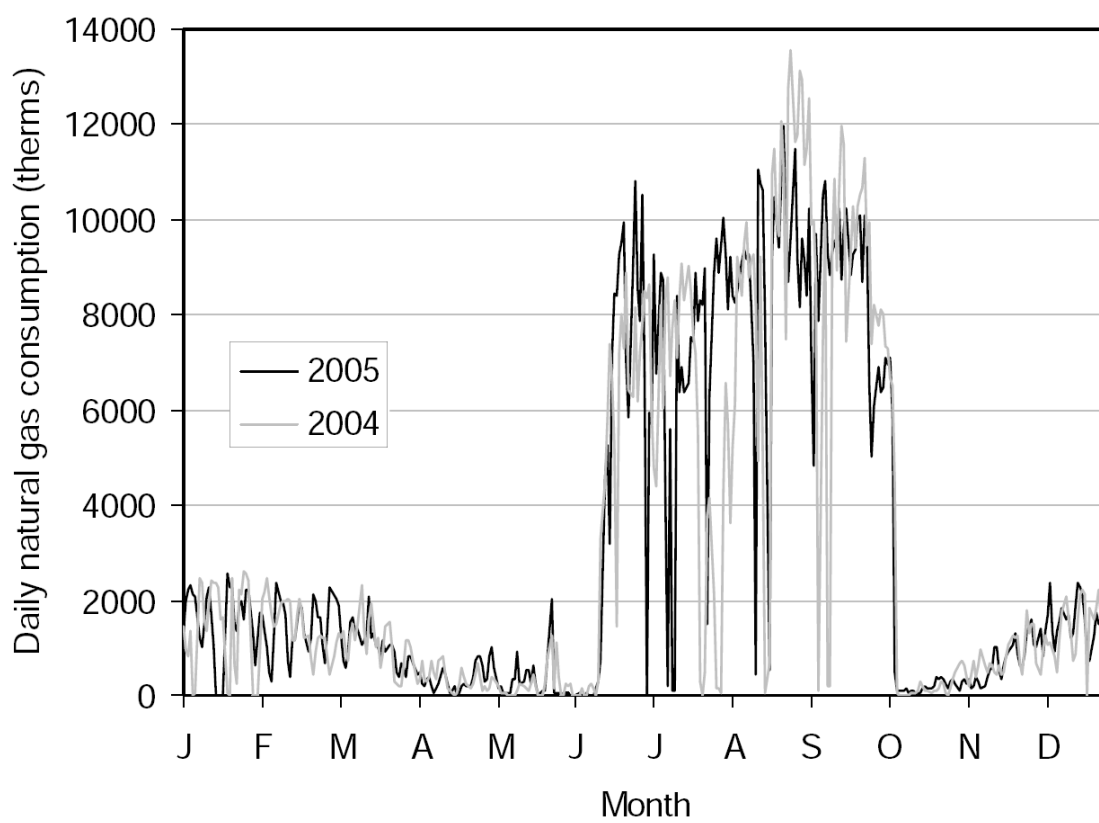


Figure 7.5: Daily natural gas consumption for Montgomery Plant, 2005 & 2006.



Table 7.3: Mean monthly natural gas usage at Seneca Foods Montgomery Plant for fiscal years 2005 and 2006 (April - March).

Billing month	Usage month	Thousand therms	Million ft <sup>3</sup>	Thousand m <sup>3</sup>	Thousand \$	% of total
April	March	35	3.5	97	23	3.2
May	April	11	1.1	30	7.7	0.98
June	May	9.1	0.9	25	6.6	0.81
July	June	118	12	325	81	11
August	July	188	19	516	131	17
September	August	267	27	734	184	24
October	September	270	27	742	209	24
November	October	56	5.6	155	50	5
December	November	23	2.3	64	22	2.1
January	December	46	4.6	126	46	4.1
February	January	50	5	136	47	4.4
March	February	49	4.9	133	48	4.3
Total		1120	112	3080	854	

made by BIOSCAN A/S. Both our predictions and BIOSCAN's predictions were made based on the composition of the material, and not actual measured gas production, though BIOSCAN did not clearly state the approach they used. However, the CH<sub>4</sub> yields we calculated from BIOSCANs predicted biogas production (490 million ft<sup>3</sup>/yr [13.8 million m<sup>3</sup>/yr]) are near the high end of published values Table 7.4. All the estimates shown in Table 7.4, apart from our low prediction, are greater than total natural gas consumption at the Montgomery plant.

It is important to note that the actual CH<sub>4</sub> yield attained will depend on specific characteristics of the waste, as well as the design of the digesters. More accurate estimates of methane yield could be made by measuring potential CH<sub>4</sub> production using batch reactors in approximately 2 months. However, for the best estimate of CH<sub>4</sub> yield, laboratory or pilot scale intermittently-fed reactors should be run. Improved predictions of total CH<sub>4</sub> production could be made given a more narrow range of values for VS concentration and total biomass production. Differences in VS concentration per unit wet mass between the first sample we analyzed (Cornell A) and subsequent samples is the reason that these biogas predictions differ from our earlier estimate (140 million ft<sup>3</sup> CH<sub>4</sub>/yr).

These results suggest that anaerobic digestion of corn biomass could offset a large fraction of natural gas consumption. However, year-round anaerobic digestion at a constant feeding rate would produce biogas at a relatively constant rate throughout the entire year, while natural gas consumption peaks around August to September. The observation that 65% of the annual natural gas consumption at the Montgomery plant is used from July through September and 81% from June through October suggests that besides the year-round option, Seneca Foods might consider starting up the digesters in the beginning of June in time for taking all available fresh silage in July through September. This alternative option would

handle much of the high natural gas requirement observed during the summer and fall months. One big drawback to this option, though, is a requirement of a much bigger digester capacity than the year-round operation.

### **7.2.3 Seneca Foods Conclusions**

1. Concentrations of volatile solids and total nitrogen in sweet corn silage samples, expressed per unit total solids, are similar among different samples and laboratories, and indicate that nitrogen should be sufficient for anaerobic digestion. A large fraction of total solids are volatile solids, and are potentially digestible for methane production.
2. Measured total solids and volatile solids, expressed per unit wet mass, show a large range among laboratories and samples.
3. Predictions of methane production show a large range because of variability in volatile solids concentrations, uncertainty in total production of biomass, and uncertainty in the methane yield.
4. Total methane production is predicted to be 190 million ft<sup>3</sup>/yr, based on a total silage production of 100,000 t biomass/yr, 20% volatile solids (% of wet mass) and typical methane yields from other studies. This value is lower than the predictions by BIOSCAN A/S, but is greater than the Montgomery plant's total annual natural gas consumption of 110 million ft<sup>3</sup>/year (3.1 million m<sup>3</sup>/year).
5. Based on low pH values and high volatile fatty acid concentrations of bunker-stored corn silage material, complete mixed digesters would be more successful than plug-flow digesters.
6. Seneca Foods should consider (i) a year round option for biogas production

Table 7.4: Predicted biogas production from Montgomery Plant food processing biomass: Cornell and BIOSCAN predictions.

Estimate	Biomass ( $10^3$ short t/yr [ $10^3$ mt/yr])	VS (% of wet Mass)	CH4 yield (ft <sup>3</sup> /lb VS [m <sup>3</sup> /kg VS])	CH4 (%)	CH4 production ( $10^6$ ft <sup>3</sup> /yr [ $10^6$ m <sup>3</sup> /yr])	Biogas production ( $10^6$ ft <sup>3</sup> /yr [ $10^6$ m <sup>3</sup> /yr])	Total NG consumption <sup>a</sup> (%)	Biogas value (\$million)
Cornell low	80 [73]	15	4.0 [0.25]	60	96 [2.7]	160 [4.5]	90	0.67
Cornell typical	100 [91]	20	4.8 [0.3]	55	190 [5.4]	350 [9.9]	170	1.4
Cornell high	120 [110]	27	6.4 [0.4]	50	420 [12]	830 [24]	370	2.9
BIOSCAN low	110 [100]	20.5	5.6 [0.35]	55	270 [7.6]	490 [14]	240	1.9
BIOSCAN high	110 [100]	20.5	6.6 [0.40]	60	290 [8.3]	490 [14]	270	2

<sup>a</sup>Notes: Total natural gas consumption was assumed to be 110 million ft<sup>3</sup>/yr (1.12 million therms/yr) from 2004 & 2005 data, the units tons used by BIOSCAN was assumed to be metric tons, gas volume in our predictions are at standard conditions (0°C and 1 atm), % of total NG consumption is based on energy content.

and (ii) a summer and fall only option to match annual peak natural gas consumption at the Seneca Foods Montgomery Plant.

### 7.3 OpTiGaS Approach for Electrical Power Onpeak Sales from Biogas to the Wholesale Market

Digester biogas production at Seneca Foods is currently mostly from leachate. The best results are for silage + leachate with an assumed annual production from 80,000 to 120,000 tons/year of corn cobs and silage and 10 million gallons of pea pack and corn pack wash water. All of the leachate was digested but only 15% of the silage was added (reference personal communication with plant manager).

They can do better than just using leachate by using all of the silage. As described in the application chapter of this dissertation, the maximum digester biogas production at Seneca Foods is projected to be from 12,000 cows<sub>equivalent</sub> of biogas in a 12 month period or 29,000 cows<sub>equivalent</sub> during the 4 month corn pack period (1/2 June, July, August, September, 1/2 October). From 2005 and 2006 data that 4 month period consume 81% of all the natural gas bills so it is possible to coordinate the seasonal peak consumption and seasonal peak biogas generation. On seasonal off peaks the factory can just buy natural gas and electricity from the pipeline and grid.

The OpTiGaS static model was used to determine the projected improvement to Seneca Foods' exported electricity.

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Determinant of A = 0.59845619

Stimulus variables input vector, b=

4,350,000.00

4,350,000.00

4,350,000.00

0.00

0.00

21.00

21.00

Solution output vector , x=

980,143.25

4,190,704.17

1,477,464.83

980,143.25

152.46

152.46

65.56

---

---

The interpretation of vector x are:

$y_{1,P1} = 980,143.25 \text{ ft}^3$  of pure  $\text{CH}_4$  per day produced by the digester and PSA,

$y_{2,P1} = 4,190,704.17$  lbs of digester slurry per day leaves the digester as effluent

$y_{3,P1} = 1,477,464.83 \text{ ft}^3$  of mixed tail gas per day used to run the onsite fuel cell continuously,

$y_{3,P1} = 980,143.25 \text{ ft}^3$  of pure methane per day used to refill the gas holder storage,

$y_{1,P2} = 152.46 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed from the stored biogas,

$y_{2,P2} = 152.46 \text{ MMBtu/hr}$  of pure methane per dispatch period consumed by the Genco MCFC to dispatch power to the grid, and

$y_{1,P3} = 65.56 \text{ MMBtu/hr}$  of recoverable heat per dispatch period that is available from the cogenerated electricity.

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Solution to 7 days of refilling the tank at 680.66 cfm  
with pure methane is:

$$6,861,002.78 \text{ ft}^3 \text{ or } 194,281.78 \text{ m}^3$$

Compare 7 days of tank refilling  $194,281.78 \text{ m}^3$ , with the  
following MCFC gas holder tank sizes:

5dx4hrs	5dx8hrs	7dx4hrs	7dx8hrs
$92,842.63 \text{ m}^3$ ,	$185,685.26 \text{ m}^3$ ,	$129,979.68 \text{ m}^3$	and $259,959.37 \text{ m}^3$

Also the onsite generator size, based on tailgas 1,026.02 cfm is:  
2.5619 MW

---

The OpTiGaS static model showed that the digester site with 29,000 cows<sub>equivalent</sub> and a enormous 21 MW fuel cell system would require a  $194,281.78 \text{ m}^3$  ( $6,861,002.78 \text{ ft}^3$ ) gas holder tanks with a continuous refill rate of 680.66 cfm of pure methane for grid power export. On the Seneca Foods Montgomery digester site itself, 1,026.02 cfm of mixed tail gas could run a fuel cell that generated 2.6 MW of power continuously. The  $194,281.78 \text{ m}^3$  ( $6,861,002.78 \text{ ft}^3$ ) gas holder storage is more than sufficient to supply 4 hrs/day x 5 days x 21 MW power and 8 hrs/day x 5 days x 21 MW power to the spot market. The flow chart in Figure 7.6 (including the 60 mile radius truckers collect corn and peas and the end uses like reed canary grass spray field, exchanging with the livestock farmers and spreading spend silage as secondary road mulch) shows the static network model for the Seneca Foods Montgomery packing plant.

The OpTiGaS dynamic model was used to determine the expected revenue from on peak dispatched power.

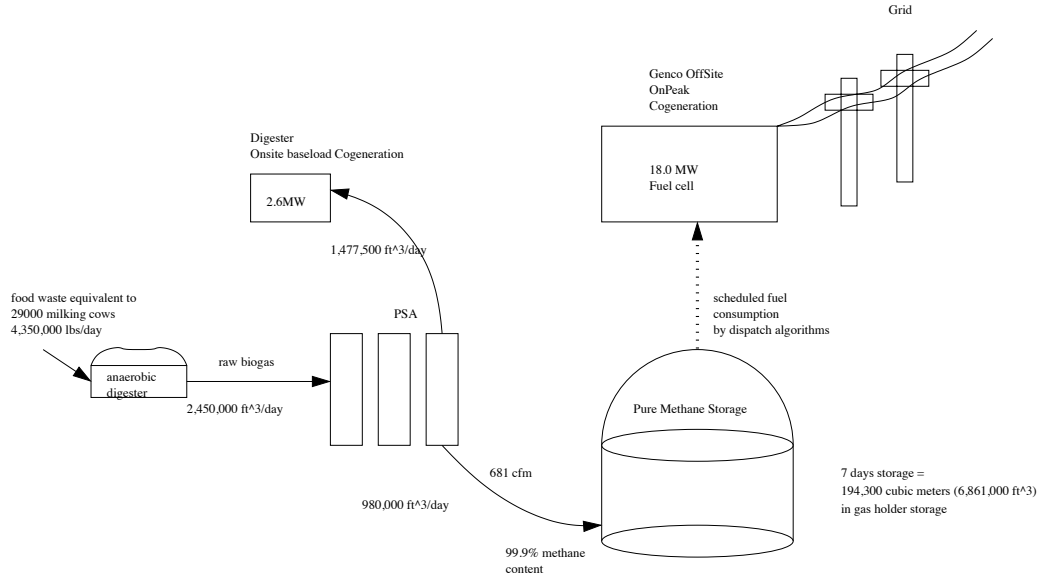


Figure 7.6: Static model flow chart for Seneca Foods Montgomery

### Applying OpTiGaS to the Seneca Foods Montgomery Digester Site

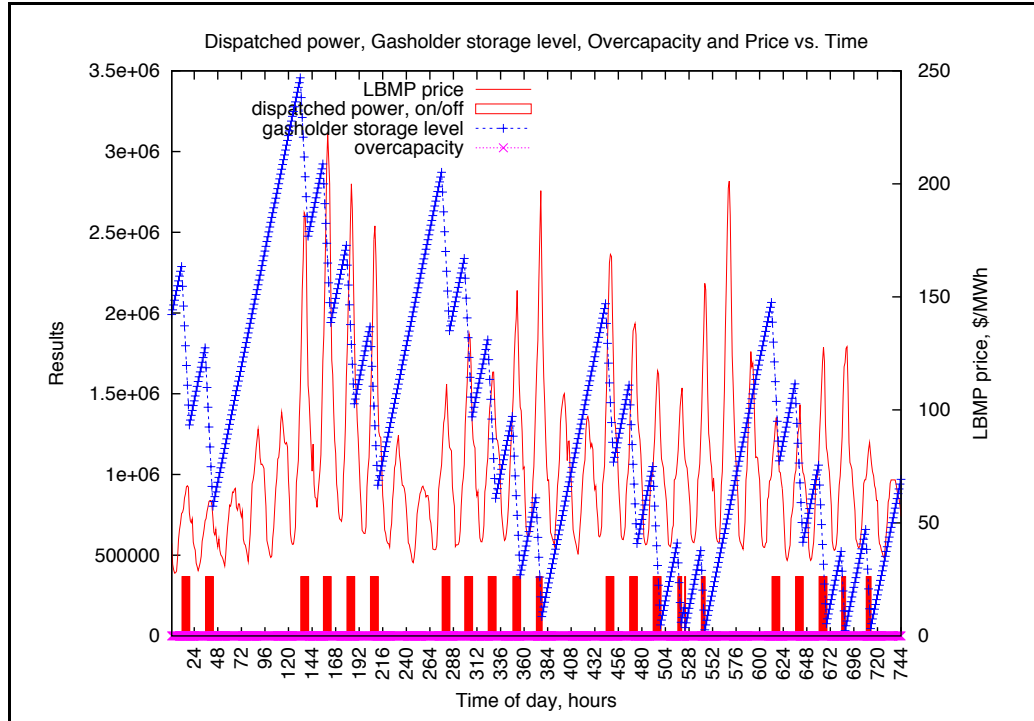
The power dispatch to the spot market using the 21 MW system connected to the 194,281.78 m<sup>3</sup> gas holder storage was simulated using the dynamic model. Like before the data set was from NYISO in July 2010 and specifically the Day ahead Marginal price data.

It is observed in Figure 7.7, that the 21 MW for 8 hours/day on spot market days from Seneca Foods would lead to under capacity problems with the gas holder because the methane consumption of the MCFC system by July 16th (384th hour) far exceeds the projected 680.66 cfm methane refilling rate of the gas holder.

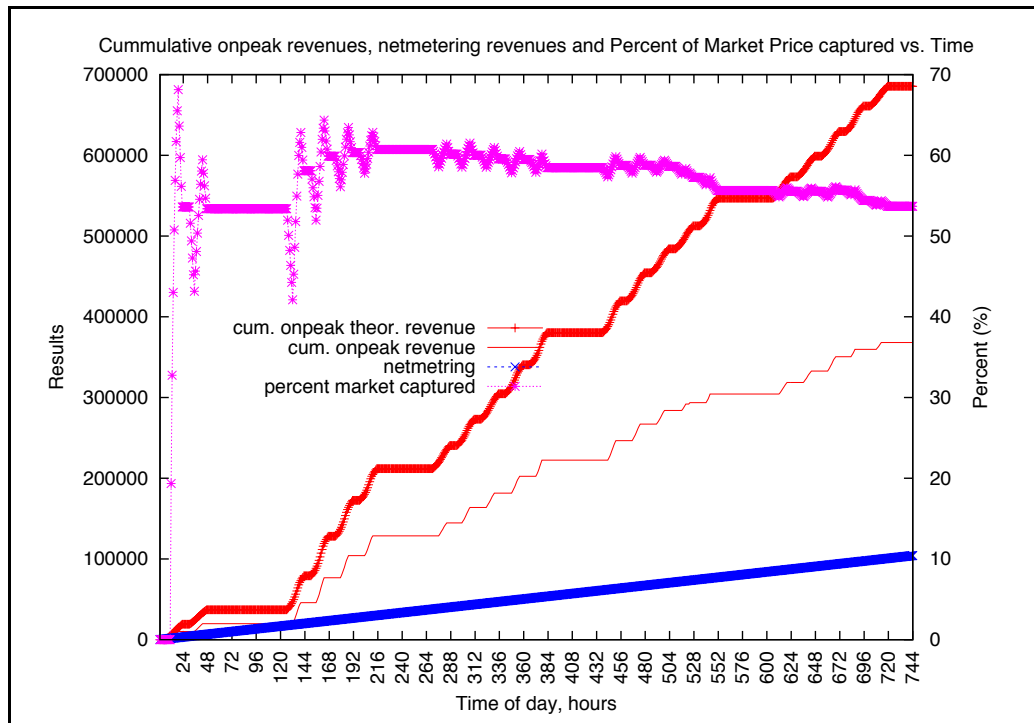
Running the fuel cell for 8hrs/day x 18 MW instead provided a remedy to methane consumption while maintaining gas storage levels that didn't cause under capacity problems of the gas holder system. The revenue collected by Seneca Foods, shown in Figure 7.8 was calculated to be around \$350,000 for July 2010, representing 59% of the theoretical spot market revenue, \$590,000.

Based on the static model and then tweaking the results with the dynamic



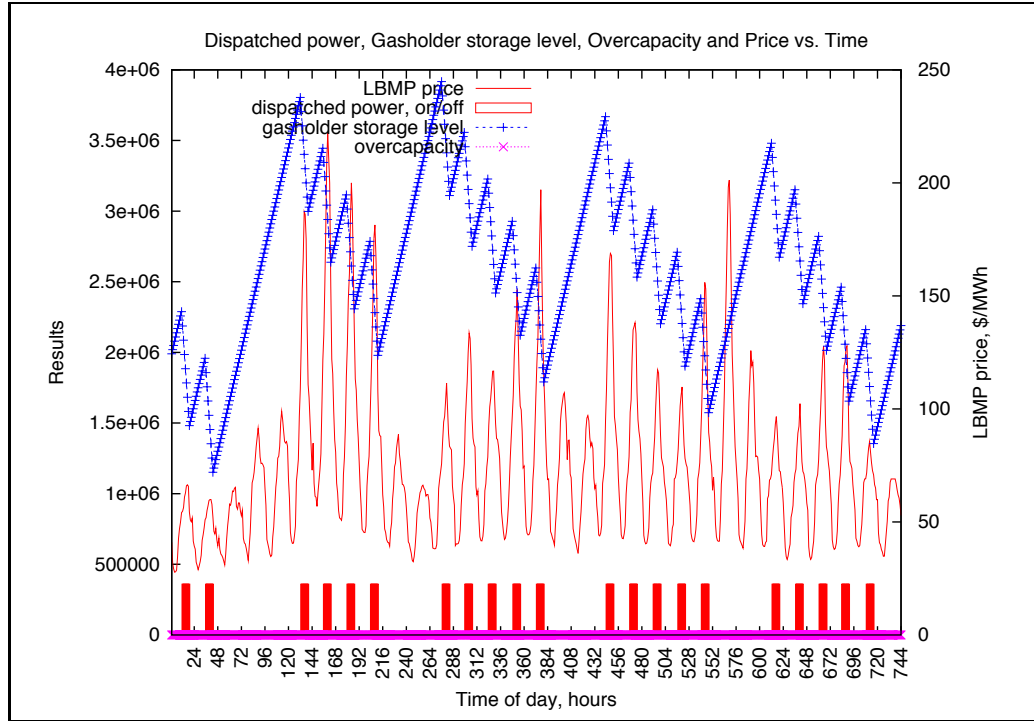


(a) Seneca Foods 29,000 cows<sub>equivalent</sub>, 21,000 kW and 8 hrs

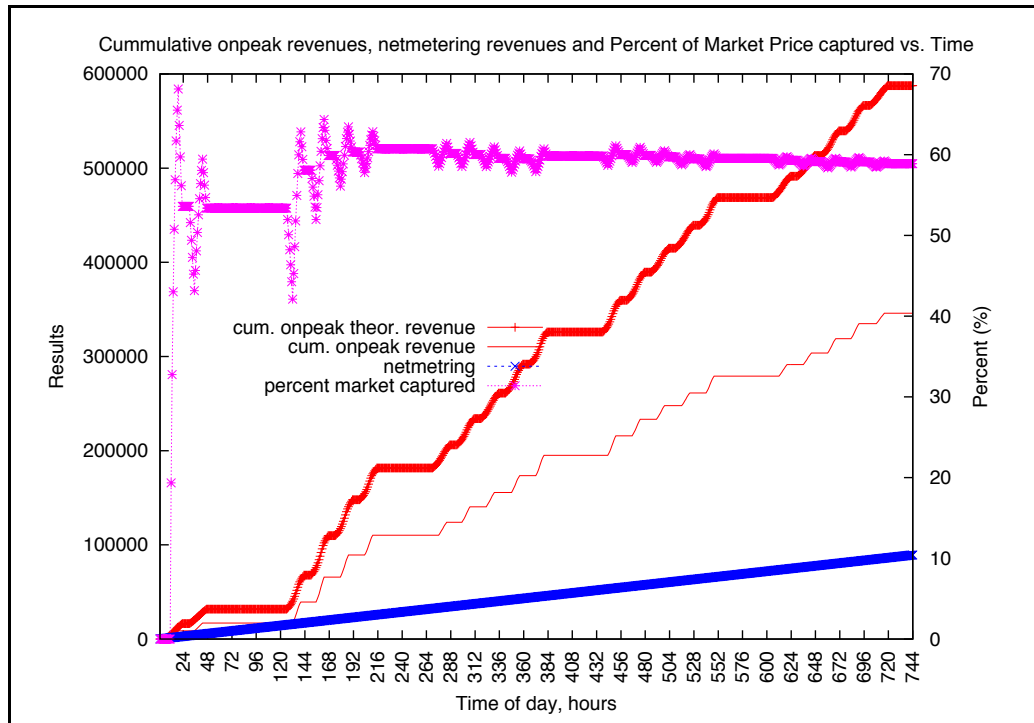


(b) Seneca Foods 29,000 cows<sub>equivalent</sub>, 21,000 kW, 8 hrs and revenue

Figure 7.7: Expected revenue at Seneca Foods when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for DDD ft<sup>3</sup>/day of digester biogas, 21 MW and 8 hrs



(a) Seneca Foods 29,000 cows<sub>equivalent</sub>, 18,000 kW and 8 hr



(b) Seneca Foods 29,000 cows<sub>equivalent</sub>, 18,000 kW, 8 hrs and revenue

Figure 7.8: Expected revenue at Seneca Foods when 31 days of historical Day-Ahead Data was simulated using the Onpeak Dispatch Model for CCC cubic ft<sup>3</sup>/day of digester biogas/day, 18 MW and 8 hrs

model, the following combination of parameters would be needed to implement the system.

1. Biomass input = biogas from 29,000 milking cows<sub>equivalent</sub>
2. Gas holder size 194,281.78 m<sup>3</sup> for pure methane = inject and wheel the pressurized natural gas through the local pipeline or fill ninety-seven 2,000 m<sup>3</sup> gas holder tanks or thirty-three 6,000 m<sup>3</sup> gas holder tanks
3. Fuel cell size for onpeak generation = 21 MW with the flexibility to throttle up or down individual units to 18 MW by shutting off unneeded generation capacity as necessary or as per dispatch schedule.
4. In July 2010 generate power for 8hrs/day per spot market day based on the OpTiGaS scheduled dispatching
5. Fuel cell size for local onsite generation 2.6 MW (nine DFC-300MA MCFC at 2.7MW running on dilute methane in the tail gas or one 2.4 MW DFC3000+ 1 DFC300MA)
6. A dedicated biogas pipeline connecting the pure methane from the methane purifying PSA at the digester site to the gas holder storage and fuel cell at the onpeak Genco.
7. Sign a tolling agreement between the Genco and Seneca Foods
8. The farm successfully fulfilling the Standard interconnection requirement document with local utility for net metering
9. The Genco successfully accepted to sell whole sale power to the NYISO spot market as a market participant
10. Internet downloading of spot market data to enable bids into the day ahead market and six day load forecast data

11. Natural gas pipeline as a backup in case of the rare situation of insufficient biogas in the gas holder

The actual measured power consumption of SFC Montgomery in July 2008 totaled 1,951 MWh at a cost of US\$110,000. Also the natural gas consumption was 229 kiloTherms at a cost of US\$293,010. Together the energy cost for one month was US\$403,010.

According to the Optigas static network model in Figure 7.6, the digester biogas production of 69,592 m<sup>3</sup>/day (2.458 million ft<sup>3</sup>/day) of biogas would be split into (i)a pure methane stream for gas holder storage at the offsite Genco site and (ii)another stream of mixed tailgas would go directly to power the onsite 2.6 MW fuel cell at the Montgomery plant.

That onsite 2.6MW fuel cell cogenerator's production of 2.6 MWelec x 24 hours x 31 days = 1,934 MWhelec of power, would be a slight shortfall from the 1,951MWh consumed by the corn and pea packing plant but the net electricity needed was projected to be only + 17 MWh compared to the actual 1951 MWh. In other words, almost zero electricity would have been purchased from the local grid in July 2008. That is equivalent to almost spending  $17/1,951 \times \$110,000 = \$958$  cash on electricity (assuming no demand charge from the local utility, or before adding the demand charge) and saving  $\$110,000 - \$958 = \$109,042$  cash on its electricity bill that month. The demand charge is the extra part of the electric bill that is not based on the total energy used but the highest/peak kW demand at anytime for the month that the utility charges the facility. The local utility does this because it has to provide that peak kW rating or higher in the future to ensure the facility has all required power to stay operational and to ensure total integrity of the rest of the local grid without power loss. To some consumers the high extra cost is a warning for them to utilizes timers and shift power consumption to less

busy times of the day. The result would be a better power factor. The higher the load factor for a facility during a month means the facility is using power effectively throughout the hours of the month instead of sharply at one or two time periods.

The other energy cost at the SFC plant was for natural gas. Using the supply from the 194,282 m<sup>3</sup> gas holders, the 18MW fuel cells generated 18 MW x 8hrs/SMD x 21days= 3,024 MWh over the 21 spot market days in July and yielded \$350,000 in revenue.

Adding up the revenue and savings versus the previous energy payments:

$$\begin{array}{r}
 \$350,000 \text{ , onpeak revenue from the power grid} \\
 +\$110,000 \text{ , onsite savings from not buying from the power grid} \\
 \hline
 = \$460,000 \\
 - \$293,000 \text{ , natural gas cost from the pipeline grid} \\
 - \$X \text{ , avoided natural gas cost from using the onsite fuel cell's recovered heat} \\
 - \$Y \text{ , avoided natural gas cost from using the Genco onpeak fuel cell's recovered heat} \\
 \hline
 = \$166,000
 \end{array}$$

which is less than or equal to the total revenue and savings from using the OpTiGaS energy System at Seneca Foods in July '2008.

The 2009 numbers are available too. Had it been the year July 2009 then the actual measured power consumption of SFC Montgomery totaled 1,526 MWh at a cost of \$126,000. The natural gas consumption was 207 kiloTherms but I didn't have the cost for that month. An educated guess puts it at around \$78,867 in 2009 using the \$3.81/1000 therms (ref ferc, 2012). Together the energy cost for

one month was around US\$204,867.

That onsite generator production of 1,934 MWh<sub>elec</sub> of power would exceed the 1,526 MWh consumed by the corn and pea packing plant therefore, the net electricity needed is -408 MWh, in other words is zero electricity would have been purchased from the local grid in July 2008. That is equivalent to \$126,000 cash being saved for Seneca Foods on its electricity bill that month plus an excess of 408 MWh for use on the plant or elsewhere on the digester site, like drying, air conditioning, and ventilation.

The other energy cost at the SFC plant was for natural gas. Using the supply from the 194,282 m<sup>3</sup> gas holders, the 18 MW fuel cells generated 18 MW x 8hrs/SMD x 21days= 3,024 MWh over the 21 spot market days in July and yielded \$350,000 in revenue. Adding up the revenues, savings vs the previous energy payments:

\$ 350,000 , onpeak revenue from the power grid
+ \$ 126,000 , onsite savings from not buying from the power grid
_____
\$ 476,000
- \$ 78,867 , natural gas cost from the pipeline grid
- \$X , avoided natural gas cost from using the onsite fuel cell's recovered heat
- \$Y , avoided natural gas cost from using the Genco onpeak fuel cell's recovered heat
_____
+ \$397,133

which is still less than or equal to the total revenue and savings from using the optigas energy system at Seneca Foods in July'09. Table 7.5 shows the projected

results for 2005, 2008 and 2009 based on Seneca Foods consumption levels.

Notice how the natural gas price soared from \$7/1,000 ft<sup>3</sup> in July 2005 to the historical high of almost \$13/1,000 ft<sup>3</sup> in July 2008 and back down to \$4/1,000 ft<sup>3</sup> in July 2009. It is now trading at \$2.67/1,000 ft<sup>3</sup> in February 2012. This roller coaster in the Natural gas price affects the electricity price and related production of goods and services. However, installing gas holder storage of pure digester methane, generating onsite power and generating Genco onpeak grid power is an effective hedge against the upswings and down swings because decisions are based on NG spark spreads and power market price signals and not the low retail power prices. Figure 7.9 shows the infamous price spikes of Hurricanes Katrina, Rita and Wilma in Aug, Sept and October 2005 that triggered SFC to launch this case study at Cornell.

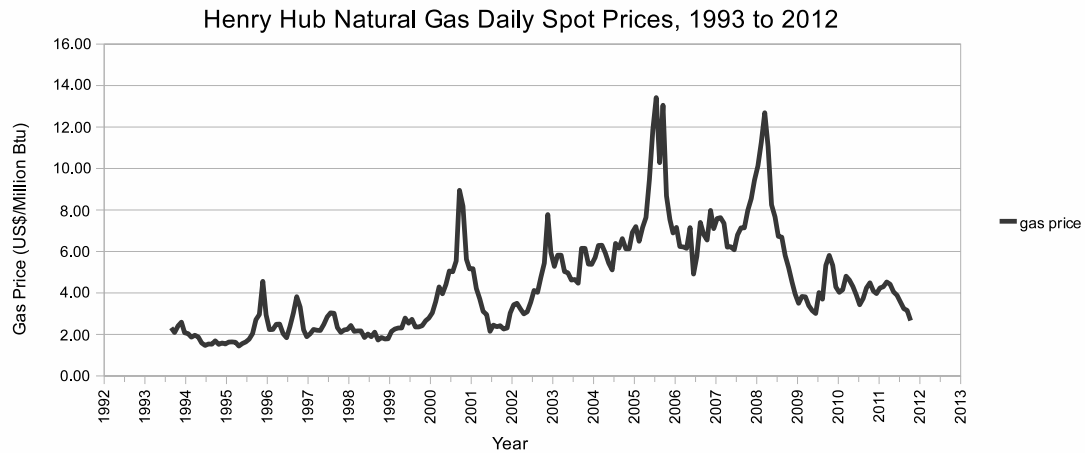


Figure 7.9: Historical spot market gas prices, (Source: Dow Jones Company Feb, 2012)

Table 7.5: Optigas projected revenue vs actual payments for Seneca Foods

Tailgas for onsite gen for Seneca Foods Montgomery	Projected MWh of onsite generation produced	Measured MWh of electricity consumed	Billed \$ payment for electricity consumed	Projected Difference in MWh purchased	Savings US\$
2005	1934	-	-	-	-
2008	1934	1951	\$110,000.00	17	\$109,000.00
2009	1934	1562	\$126,000.00	-408	\$126,000.00
Salegas stored in gas holders for Genco to grid in year	Projected power gen revenue from selling to grid	Measured 000s of therms	Billed payment for Natural gas consumed, US\$		
2005	\$350,000.00	188	\$/000 therms 6.96	\$131,000.00	difference \$219,000.00
2008	\$350,000.00	229	12.8	\$293,010.00	\$56,990.00
2009		207	3.81*	\$78,867.00	\$271,133.00



Table 7.6: 2005 SFC gas consumption

[illegible]

Table 7.7: 2008,2009 SFC gas consumption

			Gas Bills				
	complete set					almost complete set	
	2008					2009	
						Thousands of	Thousands of
Usage Month	therms	\$ /Month		Usage Month	Therms/month	\$ /Month	
March							
April	22.61	\$22,243					
May	9.85	\$11,227					
June	80.43	\$90,941		June		85.39	
July	229.26	\$293,010		July		207.05	
August	202.67	\$180,710		August		151.90	
September	212.09	\$168,046		September		120.95	
October	113.7	\$75,289					
November	24.46	\$17,634					
December	54.43	\$42,863					
January	64.3	\$49,958					
February	51.59	\$34,298					
total							
				total		565.29	

Table 7.8: 2008,2009 SFC electric consumption

	Electricity Bills									
	complete set						almost complete set			
	2008						2009			
Usage Month	kWh	Thousands \$/Month				Usage month		kWh	Thousand \$/Month	
March	197,400	12				March		233,100	15.94	
April	153,300	10				April		100,800	7.72	
May	130,200	10				May		119,700	8.62	
June	1,610,700	100				June		756,000	89.26	
July	1,950,900	110				July		1,562,400	126.4	
August	2,333,100	92				August		1,921,500	152.16	
September	2,824,500	278				September		2,354,100	172.42	
October	1,325,100	94								
November	218,400	13								
December	277,200	17								
January	264,600	16								
February	283,500	17								
total	11,568,900	770				total		7,047,600	572.52	
		\$770,260.73							\$572,516.63	

## CHAPTER 8

### SUMMARY AND DISCUSSION

This chapter summarizes the results for my dissertation. Key results from the case studies are shown in Summary Tables 8.1 and 8.2.

As described in the relevant background, Chapter 2, there is an economic problem that caused the alienation of small scale, renewable energy, independent power producers (ipps) from financially benefiting from the highest revenue making spot market that the large MW scale ipps enjoy. Without question, selling biogas power to the grid is a strong argument for adopting anaerobic digester technology at many hundreds of Dairy CAFOs and food waste processing sites throughout NY State. However, the general industry belief that small scale sub MW power generators are ineligible to make highly profitable power sales to the wholesale electric spot market causes a problem for widespread adoption at over 400 eligible sites. Very few sites, in fact, see the benefit of selling power and therefore, almost the entire industry chooses to rather to increase farm milk production revenue and increase value-added food production revenue. If they must, some of the potential digester sites believe that they would rather choose the simpler route of flaring off anaerobic lagoon (manure waste storage pond) biogas and selling carbon dioxide-equivalent credits instead of investing capital in power generation and power management for just low sub-MW net metering revenue.

Attacking this problem is precisely the reason why I painstakingly investigated a new system throughout the previous chapters. I successfully showed that it is feasible to introduce some engineered complexity to fix the problem and in the process gain simple access to higher revenue. The pursuit of this higher revenue allows a new ipp business entity called the biogas aggregating and spot market dispatching generating company (Genco) to emerge. These kinds of Gencos would

Table 8.1.1: Static Model Results from Case Studies

	cows equiv. (manure equiv.)	gen size	gas holder size	raw biogas/day	pure CH <sub>4</sub> /day	gas holder refill rate	continuous onsite gen
Digester site							
			ft <sup>3</sup>	m <sup>3</sup>	ft <sup>3</sup>	cfm	
Base Case w/ 8hrs	2,000 (300,000 lbs/day)	1.4	MW 474,000	13,422	169,490	67,596	180 kW
Base Case w/ 4hrs	2,000 (300,000 lbs/day)	1.4	MW 474,000	13,422	169,490	67,596	180 kW
Small Farm	80 (12,000 lbs/day)	0.07	MW 18,927	536	6,779	2,707	7 kW
	55 (8,250 lbs/day)	0.07	MW 13,012	368	4,660	1,860	5 kW
Small Farm Clus	825 (123,750 lbs/day)	1.05	MW 195,180	5,520	69,900	27,900	75 kW
Patterson	1,700 (255,000 lbs/day)	1.4	MW 403,000	11,412	144,000	57,457	150 kW
Patterson Alt	1,700 (255,000 lbs/day)	2.0	MW 403,000	11,412	144,000	57,457	150 kW
Seneca Foods 29	29,000 (4,350,000 lbs/day)	21.0	MW 6,900,000	195,384	2,450,000	980,143	2,560 kW
Seneca Foods 12	12,000 (1,800,000 lbs/day)	14.0	MW 2,840,000	80,419	1,016,941	405,600	1,060 kW
AADairy	600 (90,000 lbs/day)	0.45	MW 142,000	4,021	50,847	20,279	53 kW
AADairy Cluster	1,800 (270,000 lbs/day)	1.4	MW 426,000	12,063	152,541	60,758	53 kw
AADairy Expans	900 (135,000 lbs/day)	1.2	MW 213,000	6,031	76,300	30,418	80 kW
AADairy+YS+FW	1,700 (255,000 lbs/day)	1.4	MW 403,000	11,412	144,000	57,457	150 kW
Vintage Dairy Clus	11,400 (1,710,000 lbs/day)	12.0	MW 2,697,000	76,373	966,094	385,298	1,007 kW
Sunnyside Dairy	2,700 (405,000 lbs/day)	2.0	MW 639,000	18,094	228,000	91,254	240 kW

Table 8.2: Dynamic Model Results from Case Studies

Digester site	cows equiv. (manure equiv.)	best grid gen level July 2010	dispatched hrs	max theor. revenue \$	collected revenue \$	net metering \$	% increase
Base Case w/ 8hrs	2,000 (300,000 lbs/day)	1.2	8	39,168	23,063 (59%)	5,952	287%
Base Case w/ 4hrs	2,000 (300,000 lbs/day)	2	4	65,280	21,510 (38%)	9,920	117%
Small Farm	80 (12,000 lbs/day)	0.07	4				
	55 (8,250 lbs/day)	0.07	4	2,285	752 (38%)	347	117%
Small Farm Clus	825 (123,750 lbs/day)	1.05	4	34,500	11,250 (38%)	5,205	116%
Patterson Farm	1,700 (255,000 lbs/day)	1.1	8	35,904	21,141 (59%)	5,456	287%
Patterson Alt	1,700 (255,000 lbs/day)	2	4	65,280	21,510 (38%)	9,920	117%
Seneca Foods 29	29,000 (4,350,000 lbs/day)	18	8	587,523	345,942 (59%)	89,280	287%
Seneca Foods 12	12,000 (1,800,000 lbs/day)	7.2	8	235,009	138,377 (59%)	35,712	287%
AADairy	600 (90,000 lbs/day)	0.35	8	11,424	6,727 (59%)	1,736	288%
AADairy Clus	1,800 (270,000 lbs/day)	1.05	8	34,500	20,400 (59%)	5,208	292%
AADairy Expans	900 (135,000 lbs/day)	1.1	4	35,904	11,831 (38%)	5,456	117%
AADairy+YS+FW	1,700 (255,000 lbs/day)	1.1	8	35,904	21,141 (59%)	5,456	287%
Vintage Dairy Clus	11,400 (1,710,000 lbs/day)	7	8	228,481	134,533 (59%)	34,720	287%
Sunnyside Dairy	2,700 (405,000 lbs/day)	1.6	8	52,224	30,750 (59%)	7,936	287%

potentially create high paying skilled jobs for upstate New York based on the smart grid, fuel cells and year round local agricultural waste production. Participating Gencos would handle one single biogas site or cluster many smaller biogas energy producing sites if necessary to make 1 MegaWatt (MW) of power generating capacity. They would additionally manage renewable methane storage and refilling, and ultimately schedule dispatchable MW scale power in 4 or 8 hour power blocks.

The Gencos would dispatching based on spark spread data, not only on the price of any one commodity. One MW scaled ipp, or clusters of digester sites that make up 1 MW, can utilize spark spread price data to remove emotional decisions and instead dispatch power based on a computer or decision tree processes. When the spark spread is high that means the price signal is favourable then the Genco can decide to dispatch power. When the spark spread is low, that means the Genco should decide not to dispatch any electrical power during that period and instead store purified fuel for other times of the week or fuel purposes like selling purified methane to a glass blowing company or making DME or hydrogen. Biobased energy has a premium and the spark spread spot market allows premium pricing to emerge in the decisions about dispatching or not dispatching biogas, methane and electricity.

Through thousands of simulations I examined the effect of a Genco using \$/kWh and spark spread price signalling from the NYISO and other regional independent systems operator as the Genco's guide and stimulus for when to dispatch. I examined Gencos using the spark spread price signals based on Keonig's dynamic network modelling of agricultural energy systems and was able to demonstrate that high price signals stimulate the Gencos to capture the highest revenue from MW power sales during spot market periods of the week. Those high price signals indicated when the electrical grid is most stressed and when zone-to-zone power

transfer on the NYISO market is congested and in need of decongestion. Congested power lines can overload and cause power cuts and service interruption, therefore the NYISO high price signals tell registered IPPs to dispatch additional power production as well as tell registered big power consumers to reduce discretionary electrical loads.

I developed the tool called OpTiGaS, which means OnPeak Time Generation and Storage. Chapters 2, 3, 4 and 5 describe the creation and tweaking of OpTiGaS. This dynamic power dispatching tool was applied to the economic problem using many case studies from dairy biogas and food waste biogas producers. OpTiGaS was able to find rewarding solutions to fix the wide spread adoption of digesters technology problem and provide additional revenue from onpeak power sales. Those OpTiGaS based MW scale spot market sales were demonstrated to be a viable replacement for net metering. The results are summarized in Tables 8.1 and 8.2.

Table 8.1 contains the static network model results especially the 3 sought after variables from the original research question: biomass flow rate (column 2, lbs of collected cow manure equivalents per day), power generation size (column 3, in MW units), and gas holder size (column 6, in cubic meters). It also contains an additional set of results about the onsite fuel cell size (column 10 in kW units) that reduces onsite costs by buying less energy from the utility electricity grid and ng pipelines. Those being only the results for a static pure methane producing Koenig network, Table 8.1 did not have to consider whether the system is stable or unstable yet for refilling the gas holder to full capacity or the other constraint of supplying sufficient fuel for dispatchable electricity generation. On the other hand, Table 8.2 does take those constraints into consideration and summarizes the simulation- and dynamic model- optimization results, that is: dispatchable power



size to the grid (column 5 in MW units) in either one generation time block or two generation time blocks of 4 hours (column 7) and the projected increase in revenue (column 11 in \$/month.)

The two tables of results specifically answer the research question in Chapter 2 about finding combinations of three variables for a given digester site that can capture 50% or higher of the available spot market electricity prices.

Within those summary tables are 14 results from 7 locations for: 4 real operating dairy digester case studies, 1 food-waste digester case study, and also the 2 base case generic farm digester case studies with 2,000 cows and 55 cows. Each of the 14 rows of results in the tables are about the 7 locations and extra scenarios for those case study sites. The revenue collected from the power wholesale market in all of the 14 listed results show the successful combination of three variables per site that yielded more than double the revenue from plain net metered power sales to the retail market. However, the 14 results in both tables differ from each other [because that part about capturing 50% of the available spot market price was met or was not met in each case] and therefore the 14 rows of results were placed into three distinct categories:

(a) the MAIN NYISO compatible results that answer both : YES to satisfying the 1MW or higher standard interconnection requirement for selling power to the NY-ISO wholesale market; and YES to finding a farm or food processor site containing a combination of 3 values that DO captured 50% or higher of the theoretical spot market revenue;

(b) the UNEXPECTED NYISO compatible results that answer: YES to satisfying the 1MW or higher requirement for selling to the NYISO wholesale electricity market; but also NO to finding a combination that captured 50% or higher of spot market revenue; and

(c) the OTHER results that answer both: NO to satisfying the 1MW or higher requirement for selling to the NYISO wholesale electricity market; and also NO to finding a combination that captured 50% or higher of spot market revenue.

That last category, Category (c) results would be useful in regions of the USA or world where there were no minimum generation capacity size for an independent power producer (ipp) to sell 4 or 8 hour blocks of power into the wholesale power market. New York is not one of those regions because of the constraints put on ippes by the NYISO and NYPSC.

This is what the results mean: The OpTiGas tool successfully created a novel method for enlisting hundreds of additional dairy farms and food processing sites to the existing 25 sites in NY to build digesters and generate high revenue from the electricity spot market. Testing the tool showed that the research question was feasible in some scenarios. Moreover, the original hypothesis was proven definitely correct, that: making provisions for digester methane storage and scheduling the best times of the spot market day to sell MW scale fuel cell power to the wholesale grid market is a novel, feasible and economically rewarding way to sell biogas energy from digester sites.

## **8.1 Main NYISO Compatible Results**

On Patterson Farm with its 1,700 milking cow digester site, row 5 of Table 8.2 shows that the revenue calculated by OpTiGaS was \$21,141/month. This Patterson case was successful because it used 255,000 lbs manure per day, a 1.1 MW fuel cell grid connected system, 11,412 m<sup>3</sup> (403,000 ft<sup>3</sup>) gas holder and two x 4 hour blocks, to generate 8 hours of dispatchable power/day, only during on peak hours on those days when the spot market is open and gas holder storage level is high enough. Table 8.1 row 5 shows that onsite power would provide additional electricity savings at Patterson Farm by a smaller 150 kW MCFC fuel cell using the lower methane-

content tail gas from the PSA mixed with some of the purified methane from the PSA as the source of energy. However, the 2nd Patterson configuration in row 6 with a 2MW MCFC was not feasible for the OpTiGaS operating criteria that was set out in the original research question because only one 4 hour block of power generation/day would be possible for dispatching which represented 38% of the theoretical revenue available from the spot market, not 50% as required in the research question. Similarly AA Dairy Farm by itself in Table 8.2 rows 9 and 11 with no food waste added, was not be feasible for meeting all of the official OpTiGaS criteria because it would only sustain 4 hours of power generation/day or generated less than 1MW.

The base case 2,000 cow farm in Table 8.1 row 1 looked very similar to the 1st Patterson Farm case study's results. That means, the base case was definitely feasible and had a revenue of \$23,000/month using as it's parameters 300,000 lbs of manure/day, a 1.2 MW grid fuel cell, 8 hours of dispatchable power generation/day, 13,422 m<sup>3</sup> gas holder volume and a 180 kW onsite fuel cell.

In Table 8.2 row 14, Sunnyside Farm produced feasible results too. Sunnyside Farm's revenue with 2,700 milking cows was projected by OptiGaS to be \$30,750/month from 405,000 lbs manure/day, a 1.6 MW grid tied fuel cell, a 18,094 m<sup>3</sup> (639,000 ft<sup>3</sup>) methane gas holder and similarly 8 hours/day of dispatchable power on spot market days. Electricity and heating fuel savings would be realized from the onsite 240 kW MCFC fuel cell at the connected PSA gas processing and methane gas holder location. Next, in row 13, the Vintage Farm cluster with its three large interconnected farms would generate \$134,533/month in revenues from 1.71 million lbs manure/day, 7 MW grid tied fuel cell, 8 hours of dispatchable power generation/day, and 76,373 m<sup>3</sup> (2.697 million ft<sup>3</sup>) methane gas holder. Such a large dairy CAFO system could power one large onsite Megawatt scale MCFC

at the gas processing site, 7 MW, but, preferably, the mixed tail gas fuel would be split up to power three smaller onsite MCFC at the three source digester sites to provide onsite off-grid electricity and thermal energy saving to those individual farms.

Seneca Foods Montgomery plant, in row 7, was expected to produce the biggest power generation result and it did so spectacularly. Using OpTiGaS operating criteria in the 5 peak months only scenario, SFC Montgomery would have seen a combined economic increase of \$2.6 million/(year 2010) including \$471,000/month (from a combination of \$345,000/July 2010 in revenue and \$126,000/July 2010 in direct onsite electricity savings) using the equivalent organic feedstock of 4.35 million lbs manure/day from the corn cobs, corn silage, corn wash, pea waste and collected leachate, 18 MW grid MCC fuel cell, 8 hours of generated power/day, 195,000 m<sup>3</sup> gas holder, and a 2.56 MW onsite MCFC. Also, in the configuration for the year round 12 months scenario in row 8, the second SFC Montgomery case study results was successful, producing revenue of \$138,000/month or \$1.66 million using the equivalent of 1.8 million lbs of manure/day, 7.2 MW grid fuel cell, and 8 hours of power generation/day, 80,000 m<sup>3</sup> gas holder, and a 1.05 MW onsite MCFC fuel cell.

It was exciting to see the emergence and importance of two features: 1) adding food waste codigestion and 2) clustering in rows 12 and 10 respectively, that affected the feasibility of medium sized farms (500 to 900 milking cow). These important additional features in general, that were not anticipated to be relevant at the beginning of this PhD dissertation, made it possible for 2 more digester scenarios to meet NYISO requirements and all my original research question constraints.

A particularly interesting case with AA Dairy showed that a medium size farm can achieve generation capacities typical of large farms when food waste is mixed

in with the manure in the digester. Synergy in the digestion of food wastes rich in lipids and easily-degradable carbohydrates with manure, increases biogas production by 3 to 4 times. Subsequently, a medium size dairy farm could produce enough biogas to supply a Genco that is 3 to 4 times larger as well. In addition, the gas that is produced by co-digestion is of a higher quality, with approximately 10% more methane.<sup>1,5</sup> When the revenue from tipping fees and avoided costs are considered, the revenue potential in this case is significantly higher than noted in Table 8.2.

In Table 8.2 row 12, codigestion of foodwaste and manure at AA Dairy yielded revenue of \$21,141/month using the equivalent of 255,000 lbs manure/day, 1.1 MW grid fuel cell, two x 4 hour blocks of dispatchable power generation/day, 11,412 m<sup>3</sup> gas holder, and a 150 kW MCFC.

It must also be noted that an over-sized digester is not necessarily required to achieve similar results. For example, the digester on the 675-cow Ridgeline Farms (formally Matlink Farms) in Clymer, NY is about half the size of AA Dairy's digester (84,864 ft<sup>3</sup> (634,826 gallons) compared to AA Dairy's 54,600 ft<sup>3</sup> (408,436 gallons) treatment volume).

While Ridgeline Farms is comparable in size to AA Dairy, it however already accepts major shipments of food wastes that include fryer grease, hog processing waste, and ice cream processing waste, for co-digestion with the cow manure. Consequently, as reported by Scott and Ma, Matlink's digester produced almost 4 times as much biogas as AA Dairy over the 2001 to 2005 period.<sup>102</sup> So much gas was produced that only about 30% of the biogas was actually used to generate electricity (with a 145 kW genset system), 68% was flared and the balance was used to generate heat for farm operations.<sup>102</sup> Ridgeline Farm's average annual revenue of \$12,000, from net-metering is not insignificant, however it is dwarfed

by the revenue from tipping fees. At \$200 to \$400 per truck load of food waste, Ridgeline makes well over \$100,000 per year in tipping fees.

On to the matter of clustering, while most case studies show examples of various “one digester to one Genco” set-ups, there were also clustering opportunities for creating “many digester sites that deliver their fuel to one Genco site” set-ups. Clustering allows small and medium size farms to meet the 1 megawatt minimum size requirements of NYISO’s wholesale power traders and therefore allows the clusters of farm digesters or food waste digesters to participate in the New York State competitive wholesale electricity power market. Large farms with greater than 1,700 milking cows, that could independently have their own 1 MW or greater fuel cell sized Genco but choose to cluster, as in the case of the Vintage farm cluster, would save on the capital costs by putting in one purification and electricity generation systems at a central location than one purification system at each participating farm. However as we will see, small and medium sized farms had no choice but to cluster to meet NYISO and my OpTiGaS constraints.

In Table 8.2 row 10, the AA Dairy x 3 cluster yielded a revenue of \$20,400/month using an OpTiGaS combination of 270,000 lbs manure/day, 1.05 MW grid dispatchable MCFC fuel cell, and 8 hours of dispatchable power generation/day, 12,063 m<sup>3</sup> gas holder and three 53 kW on site MCFCs.

## **8.2 Unexpected NYISO Compatible Results**

We got some surprising and rather unexpected feasible results to report when we relaxed one of the constraints from the original research question. That change produced economically rewarding solutions for unclustered large and medium sized sites as evidenced in the results in rows 2, 4, 6 and 11 that sell megawatt scale power or high \$/kWh blocks of electrical power to the spot market. That constraint

from the portion of my research question that said “capture 50% or more of the theoretical spot market revenue” can be removed for further applicable feasible NYISO solutions.

By removing that portion of the research question, I was able to capture 38% of the market prices from 4 hour dispatched blocks versus 59% of the market that was possible from only 8 hours/day dispatching. That was the case for AA Dairy. That freedom allowed additional farm digesters and food waste digester sizes to participate and reap high revenue from the wholesale power market using the OpTiGaS method. For example, the other base case in row 2 also operated for 4 hour blocks/day. The revenue was \$21,510/month using 300,000 lb/day manure, 2MW grid fuel, 13,422 m<sup>3</sup> gas holder, and still the 180 kW onsite MCFC like before in the 8 hour block/day scenario of row 1.

In row 11, the expanded AADairy with 900 cows instead of 600 cows presently produced feasible results. The revenue from Optigas in this AAdairy 900 case would be \$11,831/month using 135,000 lbs/day manure, 1.1MW fuel cell, one 4 hour block of generated power/day, 6,031 m<sup>3</sup> gas holder and 80kW onsite fuel cell.

Furthermore in row 6, the second Patterson farm case study’s revenue from Optigas would be \$21,510/month using 255,000 lbs/day manure, a 2 MW grid fuel cell, the same 11,412 m<sup>3</sup> gas holder as before as well as the same 150 kW onsite fuel cell.

The most unexpected result in row 4 is theoretical. It showed a cluster of 15 small 55 cow dairies working with a Genco to produce a revenue of \$11,250/month using 123,750 lbs/manure/day, a 1.05 MW grid fuel cell, a 5,520 m<sup>3</sup> gas holder and a 75 kW onsite MCFC or fifteen 5 kW onsite fuel cells. I suggest that separate parallel return lines from the Genco site to each farm would be desirable by small digester owners to enable the tailgas to be piped back to each of the fifteen sites

to supply fuel to the fifteen onsite fuel cell CHP units.

### 8.3 Other Results

Because relaxing constraints to the objective equation was very useful in Section 8.2, it was decided to do some more tweaking of the original research question to see what the outcome would be. By further relaxing the MW scale constraint we see allowance of feasible kW scale power dispatch in Table 8.2 rows 3 and 9.

This last category of results, which we call OTHER results, showed AA Dairy unaltered in row 9 with revenue \$6,727 from using 90,000 lbs/day manure, 0.35 MW grid fuel cell for 8 hours/day, 4,021 m<sup>3</sup> gas holder, and a 53 kW on site fuel cell. It is too small for selling power based on NYISO rules but, was still quadruple the net metered revenue/month of \$1,736. That is \$6,727 vs \$1,736 which would be amazing extra cash to a farm business or food waste processor.

The generic small dairy farm with 55 milking cows in row 3 had revenue of \$757 using 8,250 lbs/day manure, a 70kW grid fuel cell, 368 m<sup>3</sup> gas holder and a 5 kW onsite fuel cell. It is definitely too small for NYISO rules or even my research question constraints but would still successfully double the \$347/month from net metering. Fifteen of these small farms are better clustered for gas cleanup and better for getting a chance to work with an aggregating Genco. This was discussed in row 4 before.

In all the cases, Table 8.2 show the cumulative revenue collected, according to the OpTiGaS dispatching schedules, was double to quadruple the revenue the site would have made with just net-metering thus the OpTiGaS dispatching schedules captured 38 to 59% of the theoretical spot market revenue over the course of a month. The percentage increase in revenue ranged from 117% to 292% (almost quadruple) higher than the net metered revenue for the same period. Sunnyside



Dairy in row 14, for instance, would have made \$30,750 dispatching electricity for 8 hours/day schedule during the peak daylight hours in July 2010 compared to \$7,936 it made over the same period with a net-metered 24 hours/day schedule.

The 14 results for experimenting with 14 farm and food waste processing digester scenarios without a doubt look very rewarding. Before discussing them let us estimate the cost of these fuel cell systems using a back of the envelope approach.

## 8.4 Estimating the Capital Cost of MCFC Fuel Cells

In this section the capital expense (capex) for a MCFC fuel cell is estimated. This helps the companies or organizations who are considering using OpTiGaS to compare the expected revenue, capex, and the numerous federal, state and local tax incentives. Whether it be tax rebate, tax credits or production incentives, there are many government programs available to invest in fuel cell power generation technology. From Table 8.1 rows 5, 12 and 1 we see that Patterson Farm and a few of the other scenarios contain the digester biogas equivalent from 1,700 to 2,000 cows. The OpTiGaS gas holder size for these case studies is 474,000 ft<sup>3</sup> or 13,422 m<sup>3</sup> which can run a 1.2 MW fuel cell. The fuel cell system configuration is either 4 x 300 kW MCFC or 1 x 1.4 MW MCFC.

Using the manufacturer's price quotes for their 3 models \*:

- \$3,600/kW for a 300 kW MCFC
- \$3,200/kW for a 1.4 MW MCFC
- \$3,000/kW for a 2.8 MW MCFC

one fuel cell stack costs  $300 \times \$3,600 = \$1.08$  million and an additional \$784,608 per 300 kW stack for the balance of plant (BOP) cost and Engineering, Procurement

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\*From personal communication with Fuel Cell Energy(FCEL) staff in 2008.

and Commissioning (EPC) cost which would bring the total cost of capital expense (capex) and installation per 300 kW fuel cell to \$1.865 million and the 1.2MW system to  $4 \times \$1.865 \text{ million} = \$7.46 \text{ million}$ . Alternatively the total capex cost for one 1.4 MW system at those case studies would be \$6.18 million (one 1.4 MW fuel cell) assuming \$1.705 million for the BOP, EPC and initial costs. Therefore, the total grid MCFC fuel cell capex for either the Patterson, AA Dairy + FW, AA Dairy x 3 cluster, and the generic 2,000 farms range from \$6.18 million to \$7.56 million.

For Sunnyside Farm with 2,700 milking cows, the OpTiGaS 1.6MW MCFC would have a total capex of \$11.2 million (six 300kW fuel cells), or \$8.05 million (one 1.4 MW + one 300 kW fuel cells).

For the Vintage Dairy Farm cluster with 11,400 milking cows the OpTiGaS 7MW MCFC would have a total capex of \$45 million (twenty four 300kW fuel cells), \$31 million (five 1.4 MW fuel cells) or \$28 million (two 2.8MW + one 1.4 MW fuel cell).

For Seneca Food Corporation's Montgomery plant with food waste anaerobic digestion equivalent to 29,000 milking cows during the six warmer months per year, the OpTiGaS 18 MW MCFC would have a total capex of \$111.8 million (sixty 300kW fuel cells), or \$80.4 million (thirteen 1.4 MW fuel cells) or \$73.3 million (six 2.8MW + one 1.4 MW fuel cells).

After investing those millions of dollars, Patterson Farms, AA Dairy+FW, AA Dairy x 3 Cluster, Sunnyside, Vintage Dairy Farm Cluster and SFC Montgomery case studies would qualify to get \$1 million in incentives from NYSERDA spread over 3 years. That is \$200,000 initially, \$300,000 at the end of year 1, \$200,000 at the end of year 2, and \$200,000 at the end of year 3.

Additionally the federal government would give those case study farms/factories

back 30% of the total system capex as a tax credit after the completion of year 1.  
That is:

- NYSERDA: \$1 million + Federal: \$ 1.86 million to \$2.27 million = \$2.86 million to \$3.27 million returned to Patterson, AA Dairy + FW, AA Dairy x 3 cluster and the generic 2,000 farms,
- NYSERDA: \$1 million + Federal: \$ 2.42 million to \$ 3.36 million = \$ 3.42 million to \$ 4.36 million to returned to Sunnyside Farm,
- NYSERDA: \$1 million + Federal: \$ 8.4 million to \$13.5 million = \$ 9.4 million to \$14.5 million returned to the Vintage Dairy Farm cluster, and
- NYSERDA: \$1 million + Federal: \$22.0 million to \$33.5 million = \$23.0 million to \$34.5 million returned to the SFC Montgomery plant.

Table 8.3a shows the breakdown for the fuel cell capital expenses for the four representative OpTiGaS digester site sizes. Previous estimates were done by our research group for pipeline gas upgrading from raw biogas, the piping cost and gas storage costs.<sup>103</sup> Table 8.3b factors in these additional pipeline gas cost estimates for these 4 farm sizes, which ranged from adding 20.10% gas piping and processing costs for the representative 1,700 cow digester site from \$6.18 million to \$7.4 million to adding 11.6% more cost for the representative 11,400 cow site from \$45 million to \$50.2 million. For Seneca Foods which is equivalent to 29,000 cows worth of biogas, the gas piping and processing cost was a lower percentage, at 7.61% of additional CapEx.

Table 8.3a: OptiGaS Fuel Cell Cost Estimates

Case Study	herd size	fuel cell		capex		government incentives available (in \$millions)	estimated payback at price	
		size	(in \$ millions)	(in \$ millions)	to \$millions)		\$0.046/kWh	\$0.15/kWh
Patterson farm	1,700	1.2	6.18	7.46	2.8 to 3.27	17	8	8
Sunnyside farm	2,700	1.6	8.05	11.2	3.4 to 4.36	17	8	8
Vintage Dairy Cluster	11,400	7	28	45	9.4 to 14.5	17	8	8
SFC Montgomery	29,000	18	73	112	23.0 to 34.5	17	8	8

Table 8.3b: Optigas Fuel Cell, Gas Upgrade, Piping and Gas Storage Cost Estimates

Case Study	herd size	fuel cell		fuel cell (in \$millions)	gas upgrade		pipeline (in \$millions)	gas storage		GU+P+GS		total capex	
		size	(in \$ millions)		(in \$millions)	to \$millions)		(in \$millions)	(in \$millions)	(in \$millions)	(in \$millions)	(in \$millions)	(in \$millions)
Patterson Farm	1,700	1.2	6.18	7.46	0.800	0.052	0.390	1.242	7.4	8.7	8.7	8.7	8.7
Sunnyside Farm	2,700	1.6	8.05	11.2	0.800	0.052	0.610	1.462	9.5	12.7	12.7	12.7	12.7
Vintage Cluster	11,400	7	28	45	3.000	0.206	2.030	5.236	33.2	50.2	50.2	50.2	50.2
SFC Montgomery	29,000	18	73	112	3.100	0.206	5.220	8.526	81.5	120.5	120.5	120.5	120.5

Looking at just the fuel cell capital expense part in Table 8.3a the payback periods for all of the greater than 1MW generating capacity fuel cell systems was around 8 to 17 years, assuming the average day ahead on peak price (\$/kWh) over the last eight years range of \$0.046 to \$0.15 and assuming the natural gas price declined from \$12/MMBtu to \$2/MMBtu. That is 8 years payback for \$0.15/kWh and 17 years payback or more years for the \$0.046/kWh. With the boom in natural gas drilling in the USA including now in 2013, the cost of generating power with natural gas based systems is a far cry from the high averages of 2005 and 2008 shown previously in Figure 7.9. But even in 2013, on the hottest day July 18, 2013, the average spot market price in New York was \$0.29/kWh at 4pm EST compared to the \$0.049/kWh at 4am the same day. Please note that OpTiGaS dispatches during onpeak times of the spot market, and the market affects the speed of payback, revenue, and profitability which is separate from the capex and government incentives.

## 8.5 Discussion

This dissertation demonstrated that making provision for methane storage and megawatt scale fuel cell generation is feasible and economically rewarding in certain situations. While it would be exciting to say it works in all cases that were tested, based on today's dairy demographics<sup>104</sup> and food waste processing stream availability, the OpTiGaS case that were shown to work best were dairy farms and digester systems with the equivalent biogas from 1,500+ milking cows. These cases satisfy both the NYISO requirements of 1 MW for continuous 4hrs blocks per day and the author's requirement of 8 hrs per day when the dispatching occurs.

The proposed OpTiGaS system works best on these case because purified methane derived from digester sites from the equivalent biogas production of a

1,500 milking cows dairy can be piped and stored for MCFC Fuel cell energy generation. Dispatching this electricity from the fuel cell converters to the spot market grid would satisfy the NYISO requirements of 1MW for two continuous 4hrs blocks of generation per day.

### 8.5.1 Observations From NY Dairy Farm Demographics

Figure 8.1 shows the total number of eligible farms greater than each size category in New York State.

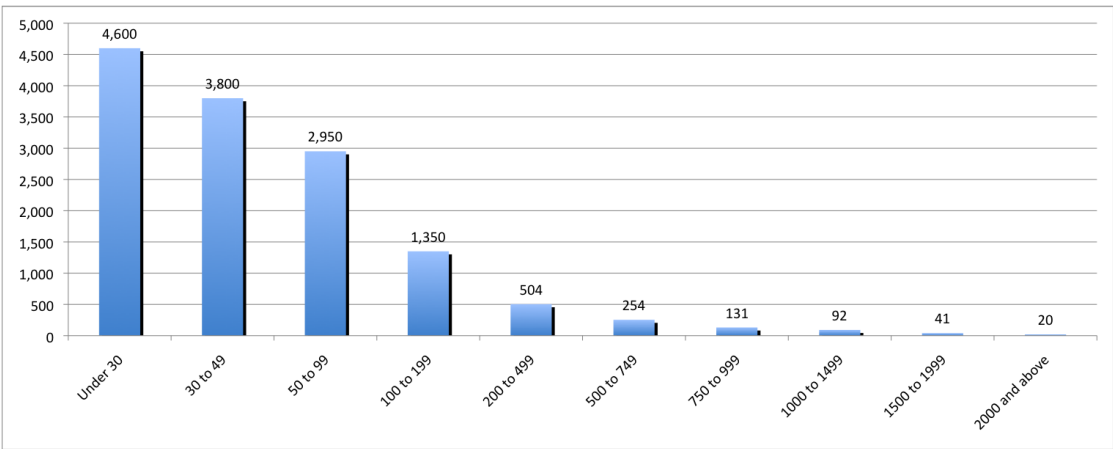


Figure 8.1: Histogram showing dairy demographics and the number of farms greater than each farm size category throughout New York State.

From Figure 8.1, there are approximately 41 very large dairy farm CAFOs in New York with 1500+ milking cows. Additionally, meeting both the NYISO and author’s requirements for MW scale generation would also apply to anaerobic digester sites that codigest certain food processing wastes with the manure and turn the digester site into the equivalent of a 1,500+ cow farm in terms of biogas production. There are 254 large farms that have 500+ milking cows in New York that can be combined with food processing waste streams to produce sufficient biogas equivalent to a 1,500+ milking cow farm.

While normally they do not qualify on the strength of manure alone, transforming these 254 farms to do codigestion with the right 3:1 manure:food waste ratios of used fryer oil or pasta or certain aquatic plant material would also fully meet the NYISO criteria and the goals of my OpTiGaS model 1MW for 8hrs per day and capture 50% of the spot market revenue for that generator. That is a 6 fold increase in eligible single farm sites if codigestion is used.

The OpTiGaS computer models showed 59% of the available spot market revenue could be earned per site, for this largest digester size range with 1,500+ milking cows and those with 500+ cows that codigested manure and food waste inputs, just like the main results in the Results chapter.

Revising down from the original research constraints, the models show it still possible to sell MW scale energy generation to the NYISO if 38% of the available spot market revenue is acceptable to the Genco operator. Although the digesters site in these situations can only generate 1MW for one 4 hour block per spot market day, they would still meet the NYISO requirements to dispatch power to the smart grid. These 38% revenue yielding digester sites fall short of the original goals of capturing 50% of the spot market revenue for that specific generator company, but it is still better than net metering during off peak and on peak hours.

This unexpected 38% yielding category increased the number of eligible farms so that a single 900 cow dairy farm and also a cluster of 825 cows, made up of fifteen smaller dairy farms with 55 or more milking cows could participate with OpTiGaS in selling electricity to the electric spot market.

There are 92 dairies state wide with 1,000 milking cows or more that can meet this level as a single farm and 131 farms with greater than 750 milking cows that might be able to reach this category too as a single farm making enough digester methane. If 92 to 131 pockets of excellence are found with these characteristics

then the number of OpTiGaS anaerobic digester generation sites can effectively double to triple from the 41 sites that were only restricted to single farms with 1,500 milking cows or more.

The aforementioned cluster of 825 cows, made up of fifteen smaller dairy farms with 55 or more milking cows, could also participate and generate 1MW for one 4 hour block per day on peak spot market days. There are 2,950 dairy farms with 50 and more milking cows that qualify to form clusters like this. Regions in New York State like Cayuga County, Wyoming County and Delaware County are good areas to search for these kinds of OpTiGaS clusters.

The 55 milking cow size was chosen because this was the smallest size that could continuously utilize the PSA tail gas to run a 5 to 7kW fuel cell like Ballard, Bloom, Bluegen (Ceramic Fuel Cell) and TMI manufacture.

Based on the dairy farm demographics in NY, it would seem to be a logical way to increase the number of digester sites from the existing 29 digester sites is by approaching the 41 dairy sites ( that are not already counted in the existing 29 digester sites) with 1500+ milking cows to get their interest in biogas digester construction and MW electricity sales to NYISO. To increase the appeal of the Genco dispatcher systems with gas holder storage and pipelines, these also proceed to superimpose that original 41 clients with the additional 2,950 dairy farms with 50+ milking cows to find natural geographic clusters in New York. This would be particularly useful to form clusters which did not require the 131 large and medium sized dairy farms. Additionally, central locations at say a food processing plant, wastewater treatment plant or a medium to large sized dairy plant could naturally be the heart of a cluster of smaller 50+ cow farms.

One of the lessons learned from this research is that there high quality spot market data that can be analyzed to match demand and supply resources. Some



are historical, some are 7-days ahead, day ahead, 1 hour ahead and 5 minutes ahead (referred to as real time forecasting given this tiny 5 minute forecast time horizon). Coming from a bioinformatics and finite element computer background, it was no problem for the author to store large data sets with the goal of finding patterns and using computer code to model systems and automate the scheduling of blocks of gas holder volume that we wanted to convert into blocks of MW scale electrical energy.

The main patterns were 1) continuously refilling the gas holders with year round digester biogas production and 2) scheduling the 4hr or 8hr blocks of time from usually Monday to Friday if those days happened to be spot market, on peak times otherwise the fuel cell dispatcher kept the generation of electricity from the fuel cells offline. Further research into this style of tuning the renewable energy system to best store biomethane, and manure derived fuels for only on peak power sales to the MW spot market is recommended.

### **8.5.2 Focus on Revenue**

These results have deliberately focused on the improvements in revenue generation and did not conduct a more detailed analysis of the profitability of each farm or food waste processor with the addition of a Genco. Such a profitability analysis is beyond the scope of this dissertation. In fact, such an analysis would be impossible to conduct at this time given the dearth of good, publicly available data on the many fuel cell systems put into operation within the last five years. My perspectives, however, are informed by discussions with experts and entrepreneurs in the field. Many details of these conversations are still protected by non-disclosure agreements. Publicly available data from the few fuel cell pilot projects run by universities and municipalities do not provide good representative estimates of the

economic parameters required to yield strong conclusions on profit in this case. This is a problem that would provide an excellent challenge for an agricultural economics graduate student. It is clear however, that in terms of revenue generation potential, the OpTiGaS method is economically more rewarding than net metering.

With the exception of the cluster of large farms in the Vintage cluster and the Seneca Foods Montgomery plant in Table 8.2 which produce vast MW scale quantities of methane under fully operational digester conditions, none of the other Gencos in Table 8.2 would be able to clear the 1 MW threshold set by NYISO for wholesale electricity market participants using a combustion engine genset. This is due to the fact that combustion engines have electrical efficiencies in the 23% to 28% range compared to MCFC electrical efficiencies of 40-65%.<sup>37</sup> Those smaller farms use combustion engine gensets now and would have to at least double their biogas production rates or the size of their gasholder storage systems to clear the NYISO 1MW threshold for compatible MW wholesale electricity market generator capacity. Furthermore at MW levels of generation, an internal combustion engine(ICE) generator set would be too polluting to receive distributed energy system permits in many states, especially California. Fuel cells and solar pv arrays are now permitted in California and many states like New York, Connecticut and Pennsylvania for clean air quality and distributed generation but existing ICE gensets have been grand-fathered in. If third party Gencos want an opportunity to try OpTiGaS in those states, the incentives for fuel cells and biogas energy dispatching has never been better.

A major barrier to the adoption of fuel cells over combustion based distributed generation systems has been the high up front capital cost. Prices have dropped steadily over the last 8 years as the annual number of fuel cell system production

has increased and manufacturing technology has improved. At the beginning of 2009 for example, the installed costs for 300 kW, 1,400 kW and 2,800 kW systems were \$3,600/kW, \$3,200/kW and \$3,000/kW respectively. At the end of 2011, these systems were \$3,500, \$2,400 and \$2,300/kW respectively <sup>†</sup>. With improvements in fuel cell manufacturing efficiencies, the prices at the higher fuel cell stack densities are falling much faster than the prices at the lower end of the generation capacity spectrum. In contrast to these prices an internal combustion engine system have much lower capital costs, ranging from \$400 to \$1,000/kW. Regardless of that disparity in capital costs, it is exciting and inspiring to see, that states like California and New York have provided policy solutions to stimulate green technology adoption and green jobs growth to reduce the up front capital cost for qualified business who want to install Fuel cells. In those two states a variety of municipal, state and federal sustainable energy incentives combine to make the capital costs for the installation of a fuel cell system on a digester site less than the cost of a combustion engine system if not zero cost for the fuel cell <sup>‡</sup>.

Installation of brand new ICE gensets are outlawed in California because they would violate the severe clean air laws in that state which suffers from smog especially in the dairy CAFO, food and agriculture dense central valley mid section of California. Someone once said it literally smells like driving for hours in concentrated cow odour in San Joaquin Valley, CA.

### 8.5.3 CAFO and Food Waste Maps

With twenty-nine digesters in operation or under construction, New York is one of the top 3 states with farm based anaerobic digesters in the country (Figure 8.2). However, there are hundreds of dairy confined animal feed operations with 400 or

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<sup>†</sup>From personal communication with Fuel Cell Energy(FCEL) staff in 2008.

<sup>‡</sup>Source: <http://www.dsireusa.org/incentives>

more milking cows. These produce high COD strength slurries that result in high VOC, odorous and greenhouse gas producing waste streams.

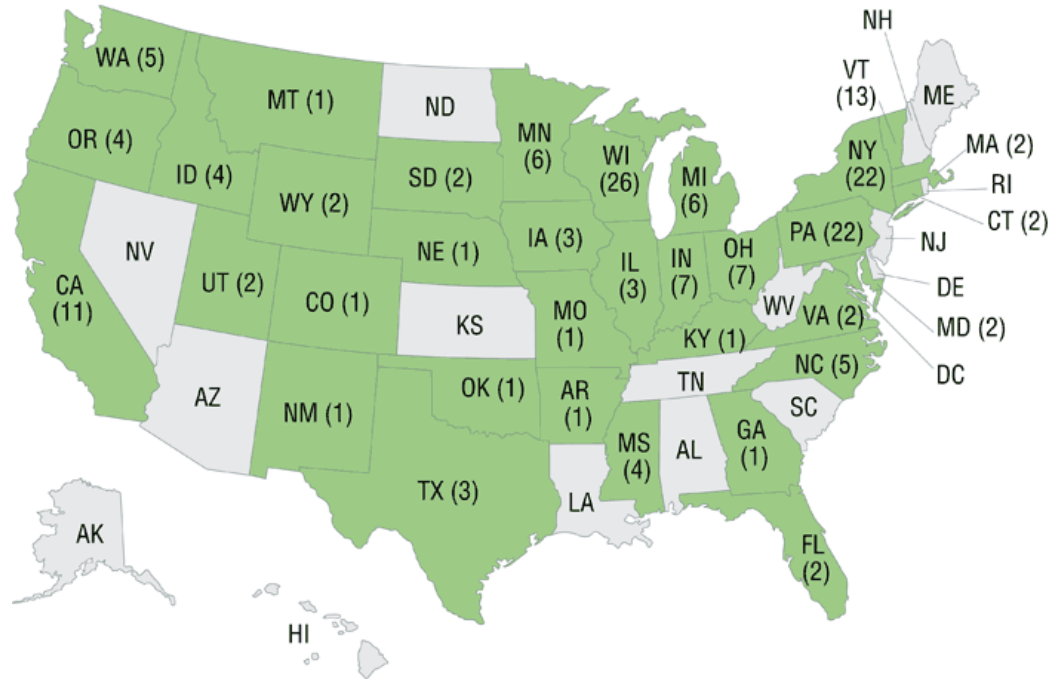


Figure 8.2: Number of operating agricultural digesters in the USA by state, as of December 2011. This includes 161 on-farm digesters and 15 centralized or regional digesters. (Source: EPA 2011)

Figure 8.3 shows the geographically dispersed dairies with more than 400 milking cows. These farms are an untapped source of abundant waste sources for energy production.

Cayuga county was identified as a excellent testbed region for constructing a 22 mile long biogas pipeline to Auburn, NY. Along this corridor a number of farms had already been operating biogas digesters or taking the initiative to install anaerobic digester power generation plants. I handpicked Patterson Farm and Sunnyside farms from the pipeline participants because they both are involved in the NYSERDA CHP monitoring program, and both sites do net metering. That means their generation and consumption data is online and publicly available for analysis. What is salient about this selection is coproduct use of the excess biogas

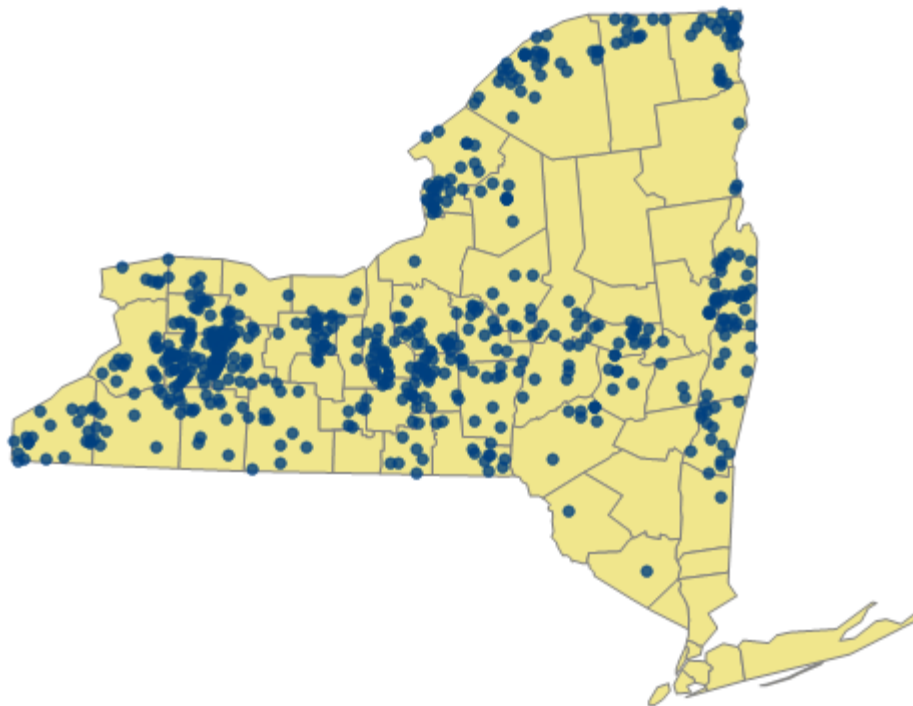


Figure 8.3: GIS map showing dairy CAFOs throughout all counties in New York State

or the constraints they face with connecting to the distribution grid provider there. Specifically, having to flare significant biogas percentage because the engine size is capped at a maximum that the distribution grid lines are capable of handling.

Medium and large dairy farms like AA Dairy, Patterson Farm and Sunnyside Farm are significant electricity consuming customers for the publicly regulated utility grids. Generation capacity is allocated by the central power plant to meet peak power needs of the dairy at all times even though the peak may only be required for a few hot summer days when extra power is required for milk refrigeration and ventilation for cow comfort. In Figure 8.4 it is clear that AA Dairy is located at the end of the transmission grid. That means the farm is located in the most electrically constrained area for power transfer and an ideal place for selling wholesale market power from MW fuel cells. This area also happens to be the first place to get a black out or brown out when power demand exceeds central power

grid supply an an ideal place to participate in Demand Response programs that shed power load when NYISO sends the impulse signal to reduce power.

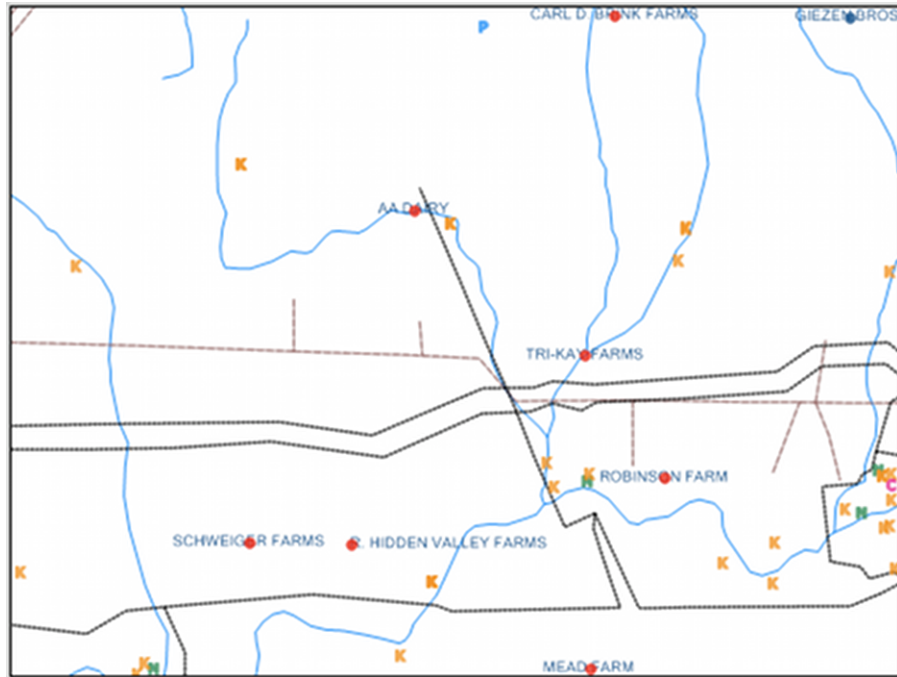


Figure 8.4: AA Dairy in a T&D constrained portion of the grid, with no natural gas but substitute propane tanks for heating fuel. AA Dairy is just a few hundred feet away from the T&D substation.

One of the most promising groups of CAFO sites in New York is Cayuga county which also has NYS's largest dairy CAFO. Most of the residences in this relatively energy constrained locale use propane instead of natural gas. There is currently a proposal to connect seven of the largest dairy farms in the area with a 40-mile gas pipeline. In the proposed system, biogas from each farm's digester would be scrubbed and then piped to a central location where it would be used to generate electricity. In addition to making money with wholesale electricity sales, the project also provides the county with a reliable local source of gas and electricity with which to attract industrial manufacturing plants.

While many technical challenges need to be worked out for the project to move forward, the economic challenges have been perceived as the most difficult

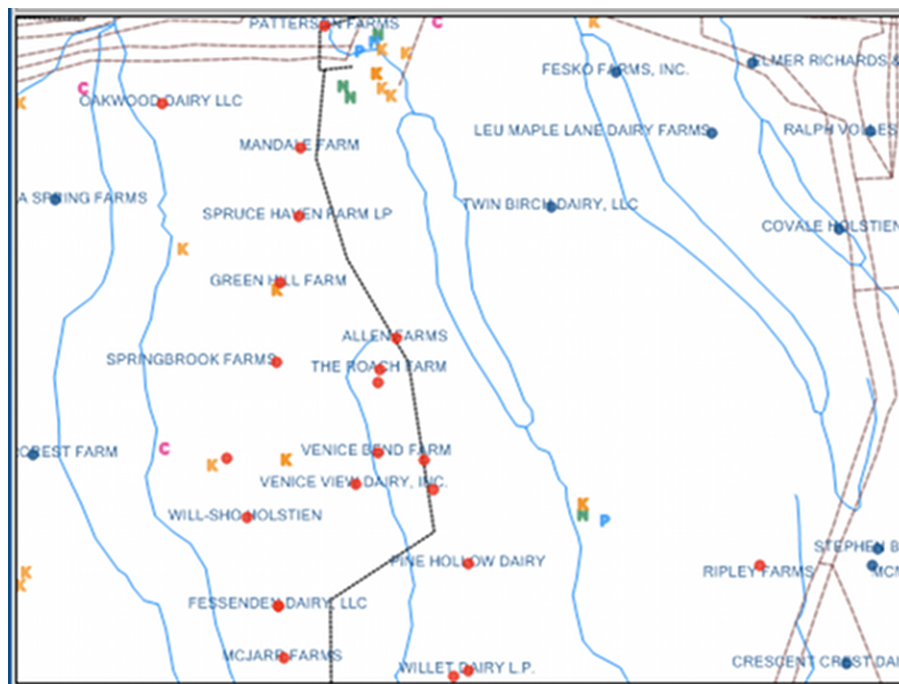


Figure 8.5: Cayuga county CAFOs relative to power transmission lines, natural gas pipelines and water bodies.

to resolve. A recent article on the project identified several problems experienced by four of the seven farms that have already installed digesters. One was the low rates paid to them by the local utility for their generated electricity. Another was the loss of on-farm energy sources for heating and electricity self-generation. Smaller farmers in the region have also protested the implementation of the pipeline since they are excluded from participation given that the economies of scale in the digester with net-metering paradigm are so unfavourable for small and even medium size farms. With the use of fuel cells capable of generating electricity from what is usually considered “waste gas” and on-site gas storage facilities, the OpTiGaS paradigm provides a solution to some of these problems. The farmers could still offset CHP energy costs while their central Genco participates in the wholesale market to reap higher prices. Small farms could participate as well, since better electricity rates make their contributions to the cluster more valuable.

Food processing plants are similar to dairy farms in that they are very large electricity consuming customers to the utility grid and also generate high COD slurries that result in high VOC and odorous waste streams. New York has about 2,300 food processing plants second only to California. As with dairy farms many of these plants are often located in electrically constrained portions of the grid. The Seneca Foods' location in Ontario county, shown in Figure 8.6 for example, is not near to the transmission power grid or main conduit of the natural gas pipelines.

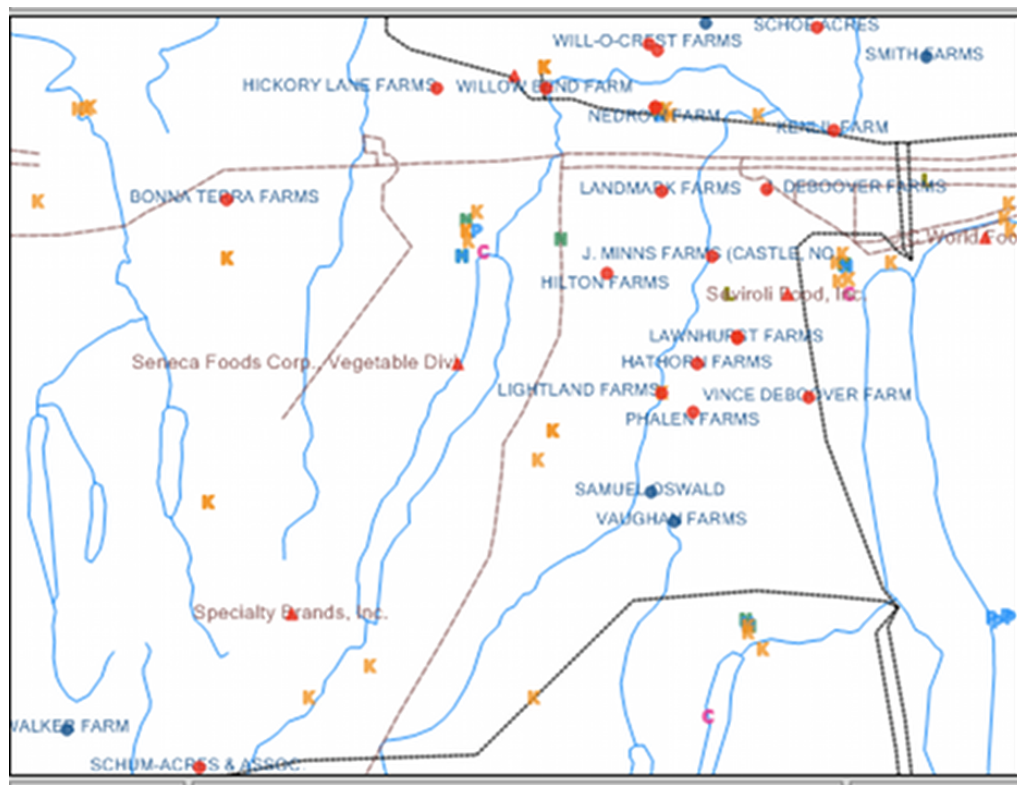
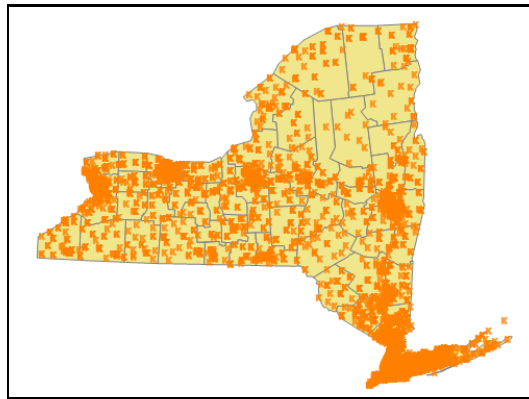


Figure 8.6: Example of a Seneca Foods location in New York.

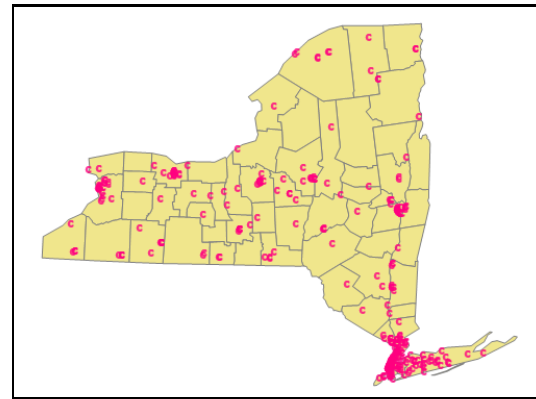
Food processing companies like Seneca foods and Wegman's could potentially team up with a cluster of dairy farmers to store energy methane in gas holders until peak time power sales to the utilities in central NYS. That is the importance of my assessing this onpeak dispatch system in dairy and food processing waste areas as natural clusters for providing clean peak time electrons to the smart grid.



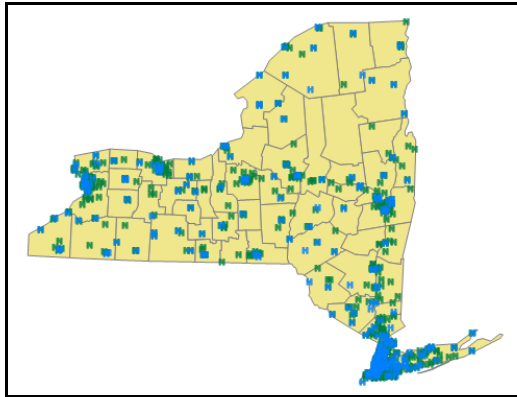




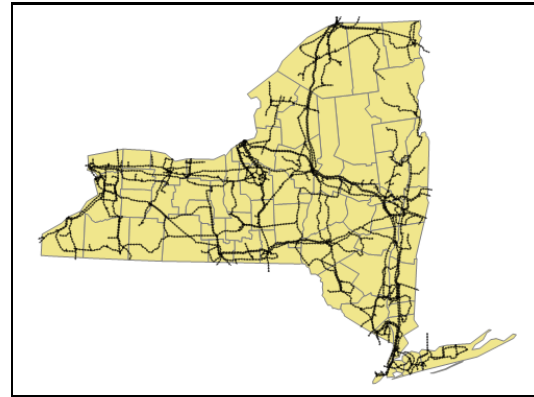
(a) Kto12 Schools



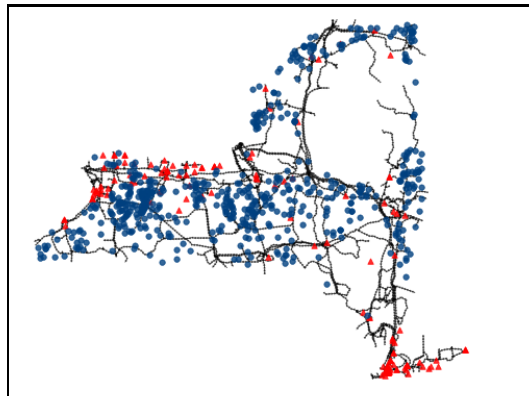
(b) Colleges & Universities



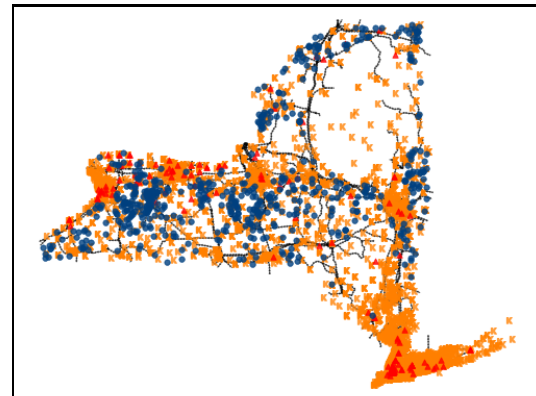
(c) Hospital & Nursing Homes



(d) NYS transmission lines



(e) Supply side CAFOs+FPs to grid



(f) Supply and Demand sides via grid

Figure 8.8: Interconnecting Electrical Power Cogeneration from CAFOs and Food Processing Waste Sites by the Grid Transmission Lines.

run from the huge hydropower plants in Canada and Western NY to New York City feeding the metropolises along the way.

New York has a very well developed competitive energy market that serves as a model of a wellfunctioning electric market. However, due to the lack of local energy resources, high demand, imported fuel transportation costs, stringent air pollution standards and grid congestion, New York also has some of the highest energy prices in the United States. Instead of just being energy consumers only, the large number of dairy CAFOs and food processing plants that the state is blessed with, can be incrementally transformed with supportive regulatory and market policies, into self supplying electricity users and then, net exporters of onpeak dispatched electricity. This dissertation is a step in realizing a waste-to-energy model that will improve the economic feasibility of the transformation process.

## CHAPTER 9

### CONCLUSIONS

New digester energy aggregating and fuel cell power plant scheduling algorithms have been presented to handle the on/off electricity selling decisions of the grid connected MCFC fuel cells at a Genco. Having made provisions for properly sized gas holder bags and methane storage tanks, the spot market triggered Genco (who uses the scheduling algorithms) can then refill the piped methane that goes into the gas holder storage from one or many digester sites who pay a tolling agreement to the Genco. This aggregation of distributed energy resources like these digester sites and fuel cells benefits the electricity consumers, farmers, Genco power plant operators and all the various energy stakeholders in between. These benefits include the economies of scale from centralized gas processing, renewable gas storage and MW scale electricity dispatching to meet the requirements of the wholesale electricity spot market.

This dissertation shows that pure methane storage and megawatt scale fuel cell systems operated by a spot market dispatcher can provide revenue streams that are double to quadruple the revenue that would be collected from net metered biogas generation. When configured as recommended, these systems can provide up to 38 to 59% of the theoretical revenue from a spot market for the generator company (Genco) that dispatches the stored energy. This research designed and developed the computer modeling approach and describes the implementation of the OnPeak Time Generation and Storage (OpTiGaS) System that achieves this level of performance. OpTiGaS presents new digester energy aggregating and fuel cell scheduling algorithms that handle the on/off selling decisions of the grid connected fuel cells at a Genco. This system is based on:

- Network models of farm based digesters and centralized digester sites;

- Computer executable simulations of biogas digester companies and an onpeak fuel cell dispatching Genco working together to maximize biogas revenue on the electricity spot market;
- A unique method of generating onpeak megawatt scale dispatching to the wholesale power grid using purified methane that is stored in gas holders at the Genco;
- Another method of onsite fuel cell generation using the dilute methane byproduct of the purifying methane at a biogas purification site that continuously provides onsite baseload combined heat and power (CHP) energy to displace purchased electricity from the grid;
- Interpretation of spot market data to fine tune the expected power dispatch pattern to minimize the risk of low and negative revenue times;
- Opening the door to higher value added fuel production for CNG, LNG and DME at the biogas purification site in situations which would cause the storage capacity of the gas holder storage to be exceeded. Before overflow occurred, OpTiGaS could divert the excess methane storage to produce higher value CNG, LNG and DME instead of heating water or simply flaring the fuel into the atmosphere.

There are up to 2,950 dairy farms in NY that could potentially benefit from digester gas generation if they are properly configured to use OpTiGaS. Forty-one of these are large enough to be configured to operate stand alone with their own Genco. For comparable outcomes, the rest can employ clustering agreements and codigestion of food waste streams to achieve similar revenue streams. The analysis demonstrated several beneficial combinations for successful identification of candidate sites:

- clustering digester sites by pipelines to make more than 1 MW fuel cell power plants if methane supply from one digester site is insufficient;
- scheduling one or two spot electric blocks totaling 8 hours/day only on spot market days for selling power to the grid, and;
- tuning gas holder size and generator size to make methane gas refilling steady each month without running empty.

Revenue from a cluster of three 600 milking cow farms and a 1.05 MW Fuel cell was up to \$20,400 per month. Revenue from one 1,700 milking cow farm and 1.1 MW fuel cell was \$21,141/month. The addition of manure to certain food wastes, such as used cooking oil and discarded pasta, was shown to transform a 600 cow biogas production to look like a 1,700 cow facility's biogas production. For a large food processing plant, equipped with an 18 MW grid fuel cell and 2.56 MW onsite fuel cell, revenue was projected to be \$2.6 million/year which combined onsite energy savings and grid power sales.

The OpTiGaS model, in its current form, is a dynamic scheduler and not an optimal dispatch solution solver. It schedules fuel cell generation to match those times of highest forecasted load demand, to maximize highest expected revenue and minimize lowest expected revenue. This leaves room for future Master's and PhD students to experiment with various linear programming or other optimization techniques to add to the functionality of OpTiGaS.

It is important to point out that the ideas presented in this dissertation can be applied to other fields beyond biogas methane storage and power dispatching to the wholesale grid and spot market. OpTiGaS as a method can equally be applied to other storable renewable energy projects such as improving landfill gas dispatching, gasified biomass power dispatching to the spot market, pumped water energy storage and compressed air energy storage (CAES). The open questions

regarding the availability of power wheeling from the source to end users using the power grid as a “wire for hire” and permitting hurdles for grid interconnection as a whole sale power market player may be difficult for regular energy generation engineers. However, that can be remedied by and recruiting lawyers, regulatory experts and professional energy auction marketers to the Genco team. There is potential to make sizable revenue for the dairy farmers in the wholesale power market that was not possible before in the traditional net metering and retail power environment.

While many wise people warn against the practice of predicting the future, it is hard to resist the temptation. I believe that OpTiGaS brings to the table a static energy networking approach and dynamic revenue model of elegance and responsiveness as to accelerate serious consideration and development of biogas clusters and fuel cell power plants. OpTiGaS Gencos and the connected digester biogas sites can provide local renewable sources of energy that can be stored, dispatched and utilized for rural community use or deliberately connected to the smart grid on the outskirts of the big electricity consuming cities. That would go a long way to making societies resilient and less vulnerable to foreign oil and gas supplies. For sure, OpTiGaS systems can help break the link of power generation and polluting the atmosphere with fossil fuel carbon.

Until dairy farm and food waste producers feel the urgency for widespread adoption of this renewable energy resource, digesters will continue to remain a novelty in agriculture and food processing industries and not the norm in New York. OpTiGaS would be a major step towards increasing the digester count in New York from 29 today to between 41 to 2,950 farms. I am optimistic that digester methane derived green electricity will supplement traditional milk and dairy revenues on the modern dairy In NY, other states and other countries that

have farms or clusters with the biogas equivalent to 1,500+ milking cows. It should be a priority to sign up eligible farms and clusters to implement OpTiGaS. When configured as recommended, these OpTiGaS sites can provide abundant local biobased electricity to eager green energy customers via the smart grid.



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## APPENDIX A

### BIOCHEMICAL FUEL PLATFORM: DILUTE HIGH STRENGTH STREAMS TO METHANE BY ANAEROBIC DIGESTION

Anaerobic digestion uses microorganisms to convert biologically volatile solids (VS) into biogas which is rich in methane and carbon dioxide ( $\text{CO}_2$ ) with trace levels of hydrogen sulfide ( $\text{H}_2\text{S}$ ). As shown in Figure A.1 Sour Gas, caused by  $\text{H}_2\text{S}$  and  $\text{CO}_2$  in the biogas, is cleaned up and conditioned to remove  $\text{H}_2\text{S}$  and moisture first. For vehicular used and natural gas pipeline injection further  $\text{CO}_2$  removal is required to purify the gas up to 95%+ Methane and subsequently it is compression and refrigerated to make higher LHV renewable compressed natural gas (CNG) or liquefied natural gas (LNG.)

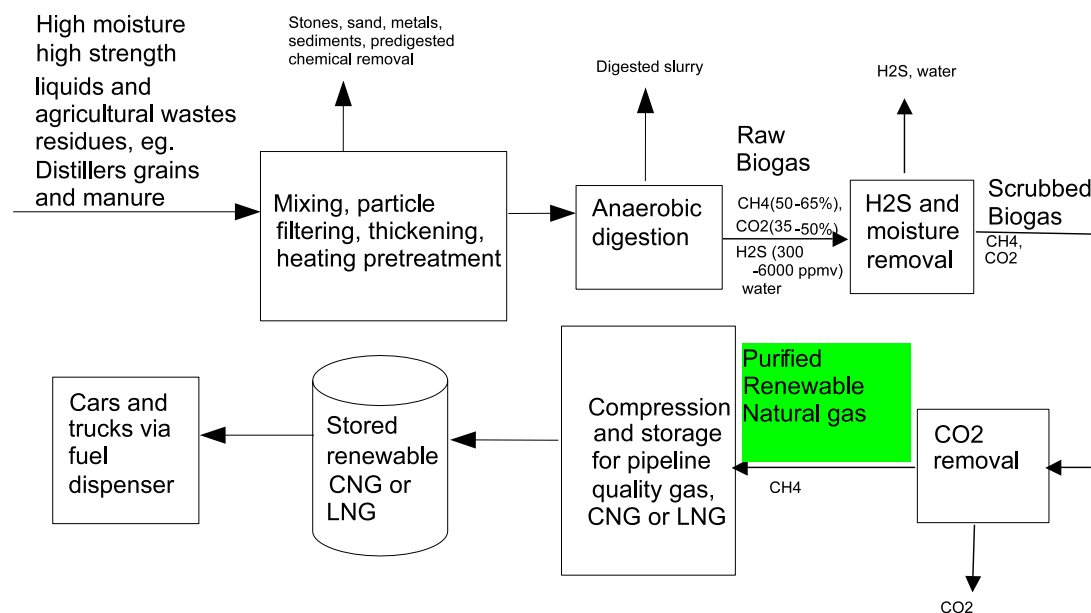


Figure A.1: Basic steps in the production of compressed natural gas (CNG) or liquefied natural gas (LNG) via Anaerobic Digestion

Because of the similarities of the biogas cleanup for pipeline quality gas and compressed CNG, LNG, it must be pointed out that the fossil fuel version for pipeline quality natural gas is a whole industrial energy network of private and

public companies. While there still remains vertically integrated systems, deregulation has broken up the supply chain into natural gas drilling and cleanup parts at the wells site, there is interstate transfer of natural gas from all over the US, large amounts from Canada, and increasingly on the eastern coast are Shipping destination points that regasify the LNG from source countries like Trinidad and Nigeria for direct pipeline injection. I say all of this to highlight that mimicking LNG, CNG and pipeline natural gas production all on on site faces economies of scale and comprehensive processing like a vertically integrated supply chain, as opposed to the bigger fossil based NG which has specialists working together and regulated by FERC to distribute the seasonal natural gas supply. Let's look at the categories of systems for making methane rich biogas from collected manure, food wastes and biomass.

The cost of the biogas purification system components depend on the method used for collecting the high strength liquids and slurries. For food processing wastes such as milk whey, corn silage, peanut wash water, tomato pure, grape skins and distillers grain, the chemical oxygen demand (COD) is too high for discharge into the regular sewage lines and waste water treatment facilities. Instead of aerobic treatment to remove COD, because we want fuel grade end products, then anaerobic treatment is the route. If the volatile solids which produces almost all of the COD content is not a high percent of the total solids going into the digester then besides biogas, large volumes of lingo-cellulosic material and inorganic materials (sand, minerals) will emerge from the digester too. These undigested materials can be composted or further processed for value added products including organic fertilizer, soil amendments, biomass feedstock for more biofuels.

To further categorize the biofuels feedstock depends on the total solids as collected. For manures, the livestock type typically determines the collection methods

and if there are compatible digester processes that is most appropriate for energy conversion. Believe it or not but some manures are not digested.

For swine almost all of the manure is flushed into lagoons. Therefore covered lagoons is the way to collect the biogas. Flushed dairy and flushed broiler in warmer climates also can be processed in a covered lagoon to make biogas which in turn can be made into CNG or LPG if economically feasible. Broiler and Turkey manures as well as horse and dry lot cattle manure are collected on a packed beds of wood chips, fibre and older manure which periodically is front loaded into piles. These piles of dry manure are typically not digested because of the vast quantity of water needed to make it suitable for pumping as a slurry. In between these ranges of too dilute and too dry material, livestock manure like scraped dairy from feedlots, food processing wastewater streams like whey and frothing peanut waste, leachates and glycerine from the biodiesel industry can be mixed and chopped to the 8-14% Total solids which is ideal for heated plug flow digesters and complete mixed digesters. These two types of digesters control the temperature of the anaerobic digestion process to tightly regulated mesophyllic temperatures or thermophyllic temperatures and may or may not use impellers, stirrers and mixing pumps to keep the total solids in uniform suspension in the liquid.

Due to the success of many large centralized digester systems for swine and industrial biowastes in Denmark and Germany, some companies like Microgy\* and Andigen† are building refinery sized manure+food waste digesters to benefit from trucking of energy rich biodegradable material and economies of scale. This removes partially some of the methane abatement burden from landfills and wastew-

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\*EPC/ Microgy, <http://www.environmentalpower.com/companies/microgy/cs-huckabay.php4>, last accessed 1/26/2009

†Andigen, Utah company that makes innovative European style digester, <http://www.andigen.com/>, last accessed 1/26/2009

ater treatment plants which traditionally have the task of collecting and purifying high strength liquids and biowastes before impacting the environment.

According to the EPA Agstar program,<sup>26</sup> the chart in Figure A.2 summarizes the technical methods to treat agricultural residues, food processing waste and livestock manure for biogas production.

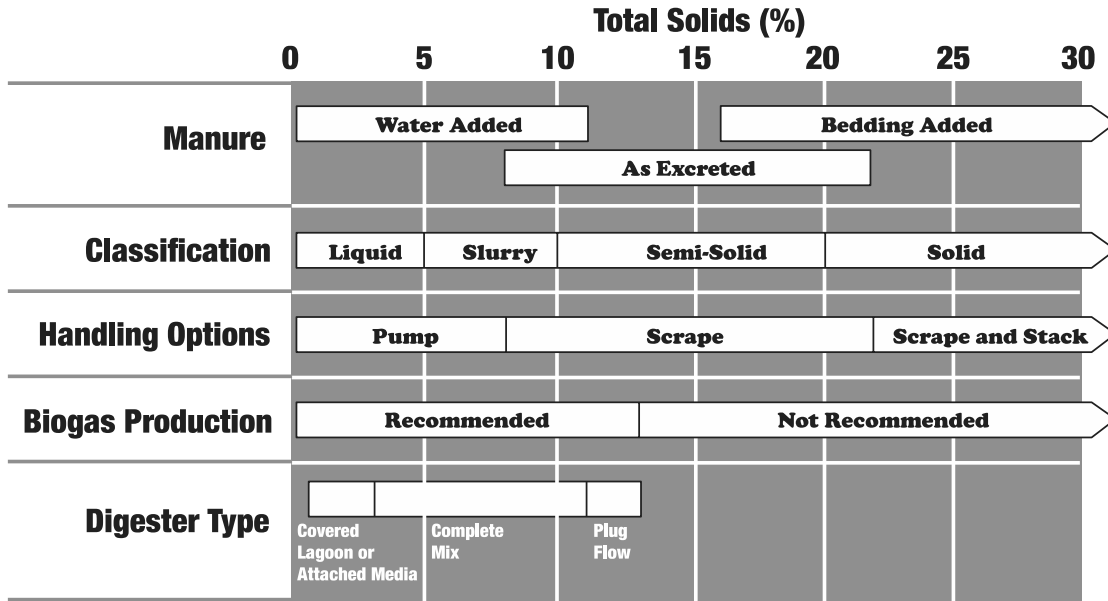


Figure A.2: Appropriate Manure Characteristics and Handling Systems for Specific Types of Biogas Digester Systems. [Source: EPA Agstar, 2010<sup>105</sup>]

Jewell and Wright<sup>106</sup> indicate that anaerobic digesters are not economically feasible with less than 500 cows or equivalent animal unit (AU). The cost per cubic foot of methane favours large Confined animal feeding operations (CAFOs) and if possible aggregated biogas production piped to a central processing site. Molecular Gate<sup>‡</sup> and QuestAir(Xebec)<sup>§</sup> sell Molecular Sieve/pressure swing absorber (PSA) technologies to separate the CO<sub>2</sub> from the methane. US Filter (now owned by

<sup>‡</sup>Molecular Gate - Carbon Dioxide Removal Systems, CO<sub>2</sub> Removal Systems, <http://www.moleculargate.com/carbon-dioxide-removal-adsorption-system.html>, last accessed 08/05/2013

<sup>§</sup>Canadas QuestAir and Xebec Join Forces, <http://www.ngvglobal.com/canadas-questair-and-xebec-join-forces-0316>, last accessed 08/05/2013

Siemens), Varec<sup>¶</sup> and New Energy Solutions<sup>||</sup> sells activated carbon filters that remove much of the hydrogen sulfide and moisture from the gases.

Tons of manure per acre is increasing each year in California, Wisconsin and New York and other dairy livestock producing states.<sup>107</sup> This is the general trend as farms are consolidating into larger CAFOs to maximize use the limited land space. Tons of food processing wastewater are also either washed into rivers or clarified in aeration technology each year as a coproduct of feeding the US population. Fortunately some facility owners are taking advantage of clean air programs and self-generation energy incentives to at least convert concentrated biodegradable liquids and solids into combined heat and power using stationary power plants. However, this stationary use of energy can be further adapted to make vehicular fuels. It all depends on the willingness to incorporate further investment in energy conversion and material processing technologies. The price signals from the market and government incentives and disincentives goes a long way to show how the biobased renewable energy resources get utilized for society's many benefits. There is a steadily rising trend towards larger dairy, swine and poultry livestock production. There is also a growing trend of food processing companies diverting waste streams directly to centralized digestion sites or trucking high strength liquid to specialized handling areas of waste water treatment plants as a way of centralizing waste treatment. This solves the aggregation suggestion in the section above because sufficient volume of biodegradable material can produce enough biogas to cost effectively utilize CNG capital investment. LNG is still not cost effective for most food processing waste site and livestock operations, although if collocated near a urban bus fleet filling station in major metropolises like Los Angeles and Minneapolis, the clean air mandates may provide incentives for renewable LNG

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<sup>¶</sup><http://www.varec-biogas.com/>

<sup>||</sup><http://www.wpi.edu/News/Conf/HFC/Presentations/newsolutionsenergy.pdf> and [http://www.biyogazder.org/makale/BioGasUnit\\_flyer.pdf](http://www.biyogazder.org/makale/BioGasUnit_flyer.pdf) [last accessed 08/05/2013]



and renewable CNG filling stations. A British company, Clean Air Power has successfully combined CNG and LNG with diesel engine trucks such that after starting the compression engines with Diesel number 2 fuel it switches to running on CNG or LNG for 50 to 80% of the diesel fuel used in driving. One California beef farm, Harris Farms\*\* has already demonstrated use of this dual fuelled system in the US and has ordered more of these modified vehicles for biogas CNG + diesel dual fuelled trucks. New York State can follow this dual fuel approach especially for milk trucks that haul between dairy farms and milk processing plants and bus fleets that have a small driving range in a predictable bus routes. If electric socket plug in versions of Toyota's Prius and the myriad of hybrid electric vehicles from Honda, Ford and GMC gain in popularity, the Stationary electric generation at centralized biogas facilities may draw more attention and importance as renewable fuels and Distributed generation gain a foothold as a option for powering cars, trucks and vehicles.

Also at least two clusters of manure producers are planning to build biogas pipelines for increase the cost effectiveness of aggregating smaller biogas streams into one big pipeline of biogas. Then it may economically be converted into pipeline quality natural gas, CNG and combined heat and power. One is located in central valley California<sup>††</sup> and the other is here in NY in County<sup>‡‡</sup>.

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\*\*UK company doing Dual-Fuel[™] trucks, Clean Air Power, US case study at Harris Farms Inc. <http://www.cleanairpower.com/dualfuelCasestudies.php?libraryId=1>, last accessed 1/26/2009

††Bioenergy Solutions, Central Valley California, PG&E and Bioenergy Solutions Turn the Valve on Californias First 'Cow Power' Project Renewable Natural Gas Made From Animal Waste to Flow Through PG&Es Pipelines, [http://www.pge.com/about/news/mediarelations/newsreleases/q1\\_2008/080304.shtml](http://www.pge.com/about/news/mediarelations/newsreleases/q1_2008/080304.shtml), last accessed 1/26/2009

‡‡Cayuga county, NY proposed biogas pipeline for 9 big dairies and connecting existing and planned digesters, contact Doug Young (Spruce Haven Farm), Connie Patterson (Patterson Dairy), Largest CAFO in NY (Willet Dairy), [http://blog.syracuse.com/news/2008/01/turning\\_manure\\_into\\_energy\\_hel.html](http://blog.syracuse.com/news/2008/01/turning_manure_into_energy_hel.html), last accessed 1/25/2009

## APPENDIX B

### **THERMOCHEMICAL FUEL PLATFORM: BIOSOLIDS TO DME, BIOOIL AND OTHER LIQUIFIED FUELS**

As suggested for the biochemical route above, the part of the dilute streams that is not volatile solids does not get converted to biogas and CNG. Material such as the manure fibers, and agriculture residue fibers can undergo more pre treatment for access to the chemical building blocks of a vehicular fuel. To break open the cell walls and release starch to make 6-sided sugars and 5-sided sugars you can pressure cook them first or microwave them to thermochemically release more volatile solids.

Much of these are jointly called thermochemical conversion of biomass and involve various levels of no- to partial- oxygen chemical conversion at different temperatures and pressures. There are fast and slow pyrolysis processes which use zero oxygen to break material down into a pyrolysis oil, solid char or ash, and gaseous portion. There is gasification, which uses partial oxygenation to convert the biomass feedstock into the syngas mixture of CO and H<sub>2</sub>.

Technology derived from 1970s work at MIT called super critical water gasification<sup>108</sup> can convert all of the carbonaceous influent, not into biochemical building blocks but into simpler mixtures of Carbon monoxide, Hydrogen and Methane, which is called synthesis gas or syngas as discussed in other sections of this report. To reach some of these higher temperatures some of the fibrous material can be combusted to provide the boiler heat, if separate pipeline natural gas or propane is not preferred. SCWG does not require moisture removal since the water is itself a reactant and the suspension medium.

Simple gasification can be done if biological solids are cycloned, screen-filters, or screw pressed to remove much of the water first. This added dewatering step is

beneficial when the dewatered material is intended to be driven or transported to a centralized processing site leaving the water to be used at the farm for irrigation and other uses.

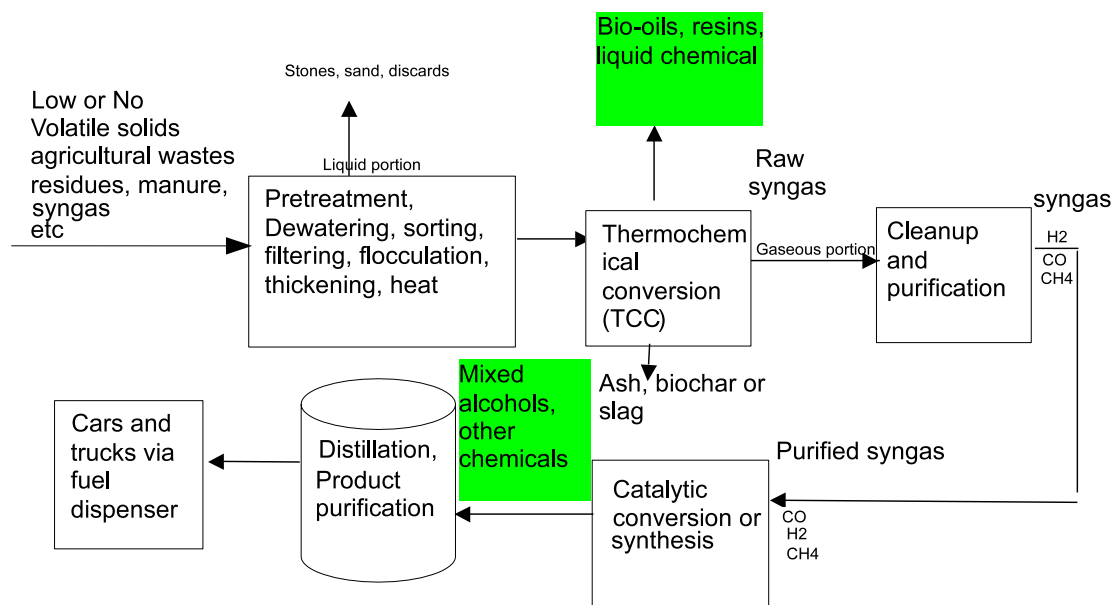


Figure B.1: Basic Steps for Syngas-Derived DME, Methanol and Other Alcohols as Well as Bio-oils via Thermochemical Conversion

Once the volatile solids pre TCC have been utilized, the processes in Figures A.1 and B.1 can be combined to build a biorefinery platform with combines pretreatment, biochemical/enzymatic conversion and thermochemical/catalytic conversion to make multiple product streams if sufficient high moisture biomass feedstock is available to make the combined systems economically feasible.

APPENDIX C  
DIAGRAMS

Diagram of dairy digesters and high temperature fuel cells

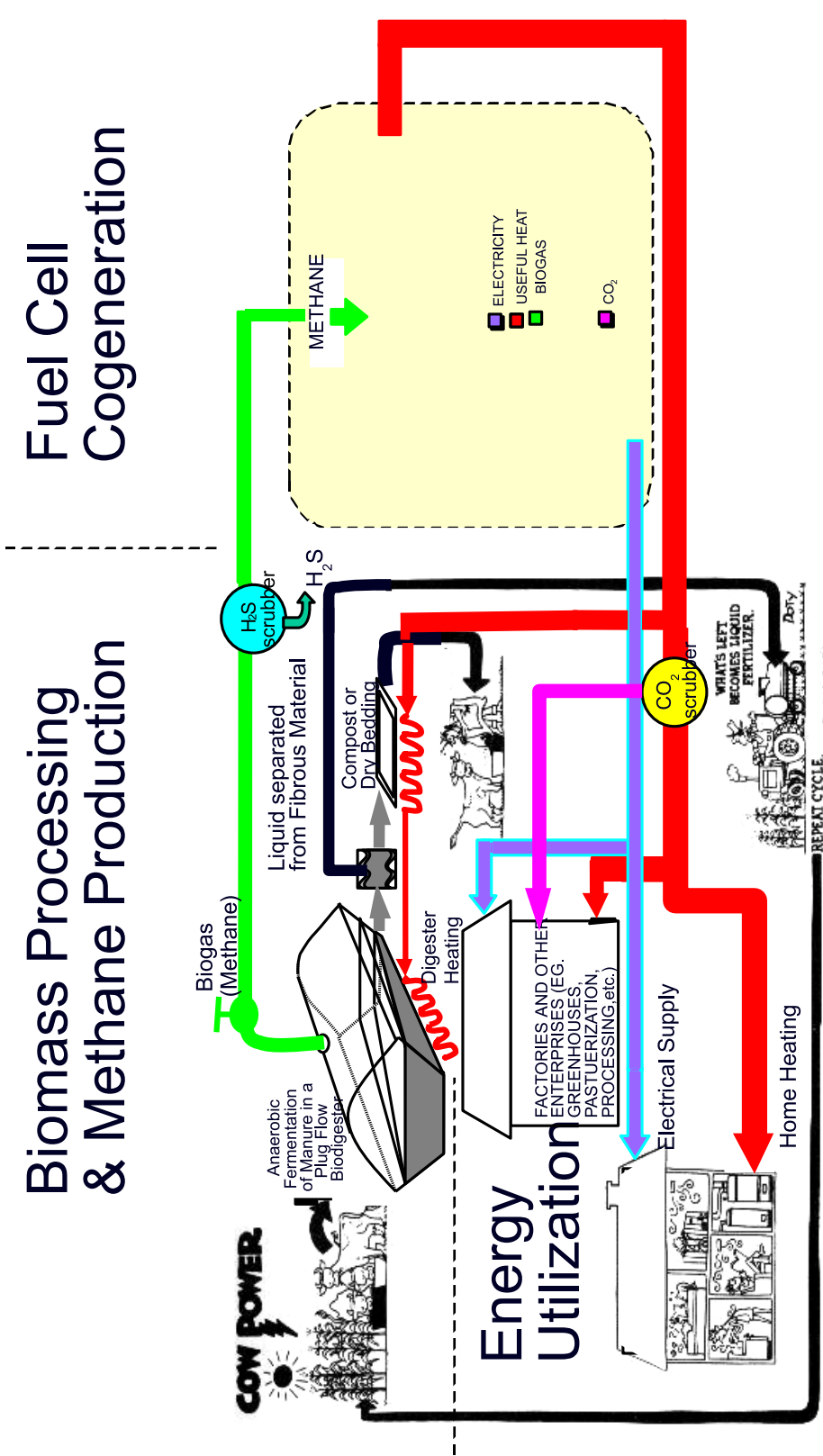


Figure C.1: Integrated Biogas Fuel Cell System from Masters Thesis

## Diagrams of long term vision

My vision of what a digester-based fuel supply chain should look like for making DME and other liquid automotive fuels is shown in the flow diagrams Figures C.2 and C.3. In those diagrams technologies are used to convert biobased resources, such as anaerobically digested manure and food wastes, via a number of different value-added processing pathways into my final products: methane and liquids fuel that can be stored for onpeak power, heating fuel and automotive fuels like DME and LNG.

The process for producing fuel grade DME from digester methane would be inserted into an existing dairy facility as shown in Figure C.4.

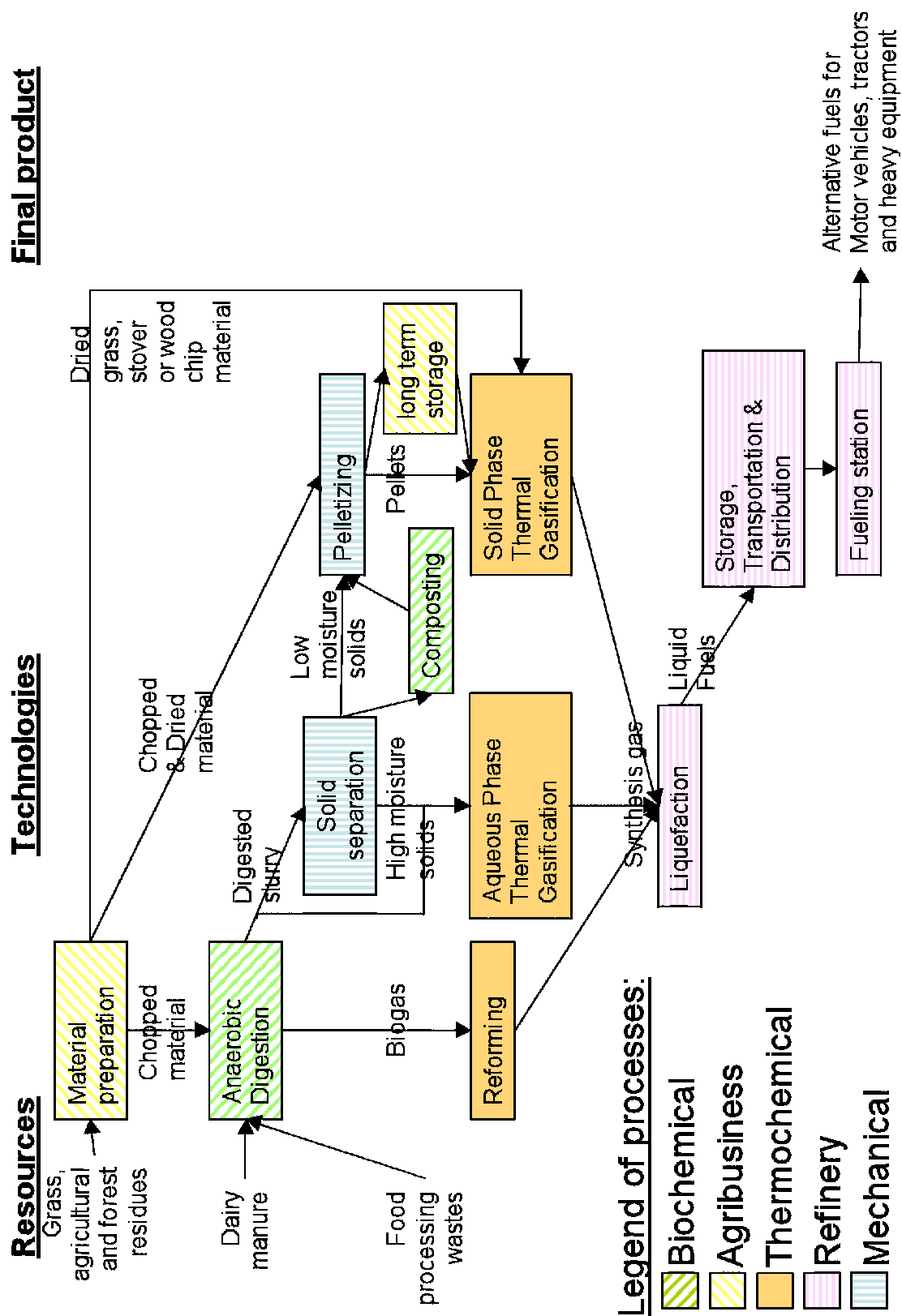
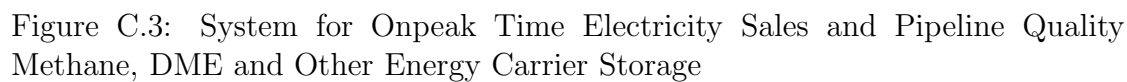


Figure C.2: Biofuel Supply Chain for DME and Other Automotive Liquid Fuels





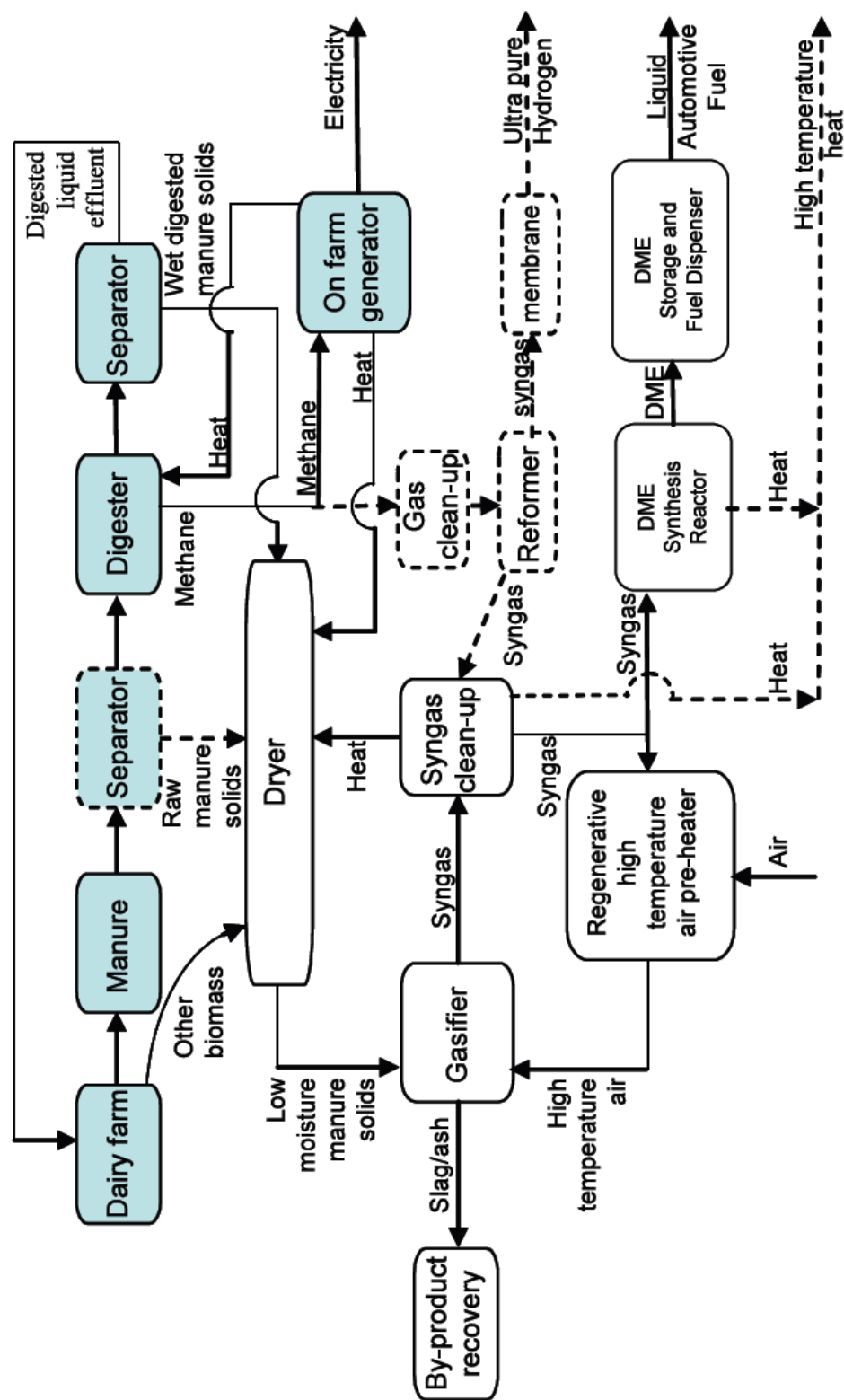


Figure C.4: Schematic of an existing dairy farm digestion system (shaded boxes) with the proposed additions (unshaded boxes) for gasification, fertilizer recovery and DME liquid fuel synthesis.

APPENDIX D

**OPERATIONAL DAIRY DIGESTERS IN NY**

Table D.1: EPA Dec 2011 List of Operational Digesters in NY; Modified from Source: EPA 2011

Farm/Project Name	City	County	Digester Type	Status	Since	Farm Type	Cows	Biogas End Use(s)
AA Dairy	Candor	Tioga	Horizontal Plug Flow	Operational	1998	Dairy	600	Cogeneration
Aurora Ridge Dairy	Aurora	Cayuga	Mixed Plug Flow	Operational	2009	Dairy	1800	Electricity
Boxler Dairy	Varysburg	Wyoming	Mixed Plug Flow	Operational	2009	Dairy	1700	Cogeneration
Coyne Farm	Avon	Livingston	Covered Lagoon	Operational	2008	Dairy	1100	Flared Full Time
EL-VI Farms	Newark	Wayne	Horizontal Plug Flow	Operational	2004	Dairy	1500	Boiler/Furnace Fuel
Emerling Farms	Perry	Wyoming	Horizontal Plug Flow	Operational	2006	Dairy	1200	Cogeneration
Fessenden Family Dairy	King Ferry	Cayuga	Covered Lagoon	Operational	2008	Dairy	800	Electricity
Lamb Farms	Oakfield	Genesee	Mixed Plug Flow	Operational	2010	Dairy	2000	Electricity
Patterson Farms	Auburn	Cayuga	Complete Mix	Operational	2005	Dairy	1760	Cogeneration
Ridgecrest Dairy	Genoa	Cayuga	Covered Lagoon	Operational	2008	Dairy	1650	Flared Full Time
Ridgeline Farm	Clymer	Chautauqua	Complete Mix	Operational	2001	Dairy	525	Cogeneration
Roach Dairy Farm	Scipio Center	Cayuga	Complete Mix	Operational	2010	Dairy	1350	Electricity
Sheland Farms	Adams	Jefferson	Complete Mix	Operational	2007	Dairy	625	Cogeneration
Sunny Knoll Farm	Perry	Wyoming	Horizontal Plug Flow	Operational	2006	Dairy	1800	Cogeneration
Sunnyside Farms	Scipio Center	Cayuga	Mixed Plug Flow	Operational	2009	Dairy	2700	Electricity
SUNY at Morrisville	Morrisville	Madison	Horizontal Plug Flow	Operational	2007	Dairy	505	Cogeneration
Swiss Valley Farms	Warsaw	Wyoming	Mixed Plug Flow	Operational	2009	Dairy	850	Electricity
Twin Birch Dairy	Skaneateles	Cayuga	Horizontal Plug Flow	Operational	2003	Dairy	1900	Electricity; Boiler/Furnace Fuel
Wagner Farms	Poestenkill	Rensselaer	Complete Mix	Operational	2010	Dairy	350	Cogeneration
Will-O-Crest Farm	Clifton Springs	Ontario	Covered Lagoon	Operational	2008	Dairy	1050	Flared Full Time
Zuber Farms	Byron	Genesee	Complete Mix	Operational	2009	Dairy	1800	Cogeneration

Table D.2: EPA Dec 2011 List of Operational Digesters in NY(continued), (Modified from Source: EPA, 2011)

Farm/Project Name	Installed kW	Baseline System	Reductions metric tons CH <sub>4</sub> /yr	Reductions metric tons CO <sub>2</sub> E/yr
AA Dairy	130	Storage Tank or Pond or Pit	39	826
Aurora Ridge Dairy	500	Storage Tank or Pond or Pit	118	2477
Boxler Dairy	500	Storage Tank or Pond or Pit	111	2339
Coyne Farm		Storage Lagoon	221	4646
EL-VI Farms		Storage Tank or Pond or Pit	71	1483
Emerling Farms	230	Storage Lagoon	229	4814
Fessenden Family Dairy	500	Storage Lagoon	161	3379
Lamb Farms	450	Storage Lagoon	402	8447
Patterson Farms	250	Storage Tank or Pond or Pit	88	1849
Ridgecrest Dairy	370	Storage Lagoon	332	6969
Ridgeline Farm	130	Storage Tank or Pond or Pit	34	722
Roach Dairy Farm	300	Storage Tank or Pond or Pit	79	1650
Sheland Farms	125	Storage Tank or Pond or Pit	38	802
Sunny Knoll Farm	230	Storage Lagoon	314	6584
Sunnyside Farms	500	Storage Lagoon	543	11403
SUNY at Morrisville	50	Storage Tank or Pond or Pit	29	612
Swiss Valley Farms	300	Storage Tank or Pond or Pit	56	1170
Twin Birch Dairy	180	Storage Tank or Pond or Pit	97	2034
Wagner Farms	100	Storage Tank or Pond or Pit	23	482
Will-O-Crest Farm		Storage Lagoon	211	4435
Zuber Farms	400	Storage Tank or Pond or Pit	110	2311